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Technical Assessment of Thermal DeNOx Process

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Technical Assessment of Thermal DeNO$_x$ Process

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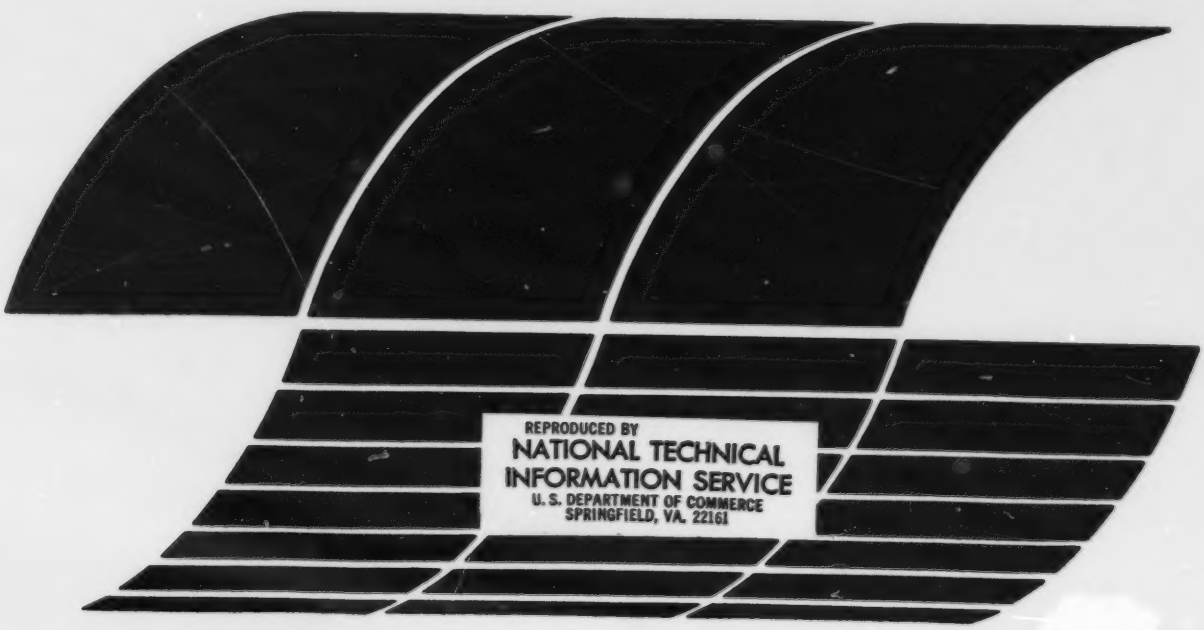

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16. ABSTRACT The report gives results of a technical/economic assessment of Exxon's Thermal DeNOx Process, applied to coal-fired utility boilers. The assessment was performed in parallel with a study in which the performance/cost of the process was estimated for eight coal-fired utility boilers representative of the Nation's boiler population. The report concludes that the process is a promising technique for controlling NOx emissions from utility steam generators. However, a number of limitations need to be evaluated when the process is retrofitted to coal-fired boilers. Flue gas temperature fluctuations (caused primarily by load following, furnace slag deposition, and tube fouling) may limit NOx reductions to approximately 50%. In addition, operational and environmental impacts of NH3 emissions and ammonium bisulfate formation could further limit the performance of the process and affect its applicability. These limitations are best evaluated on full scale. Total operating costs are estimated between 0.27 and 1.23 mills/kWhr, exclusive of license fee. Actual costs depend primarily on boiler size, initial NOx concentration, and level of control required. The assessment also considered the impact of widespread process implementation on the ammonia market, feedstock supplies, and their costs. The impacts were found to be small.

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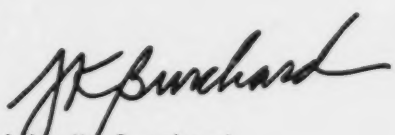
FOREWORD

Two studies relating to Exxon's Thermal DeNO$_x$ Process for control of NO$_x$ emissions from utility boilers have been sponsored by EPA/IERL-RTP. One, conducted by Exxon Research and Engineering Company under EPA Contract 68-02-2649, is entitled "Applicability of the Thermal DeNO$_x$ Process to Coal-fired Utility Boilers." The final report number is EPA-600/7-79-079, March 1979. The other, conducted by Acurex Corporation under EPA Contract 68-02-2611, is entitled "Technical Assessment of Exxon's Thermal DeNO$_x$ Process." Its final report number is EPA-600/7-79-111, May 1979.

The Exxon-prepared report discusses the Process background, engineering considerations, and cost estimates for application of this technology for a number of boiler/fuel cases at various NO$_x$ control levels. Results of recent pilot-scale tests with coal-firing, sponsored by Exxon and the Electric Power Research Institute, are included.

The Acurex-prepared report objectively critiques the Exxon findings and also addresses a variety of environmental, operational, and supply/demand considerations that are relevant to the Thermal DeNO$_x$ Process.

Together, these reports give a good overview of this technology. We recommend that both reports be obtained, and read, by those wishing to become better informed about the Thermal DeNO$_x$ Process.



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ABSTRACT

This report presents results of a technical and economic assessment of the Exxon's Thermal $DeNO_x$ Process applied to coal-fired utility boilers. This assessment was performed in parallel with a study conducted by Exxon Research and Engineering Co. (ER&E) in which the performance and cost of the Thermal $DeNO_x$ Process were estimated for eight coal-fired utility boilers representative of the nation's boiler population. This report concludes that the Thermal $DeNO_x$ Process is a promising technique for control of NO_x emissions from utility steam generators. However, a number of limitations need to be considered and evaluated when the Process is retrofitted to coal-fired boilers. Flue gas temperature fluctuations caused primarily by load following, furnace slag deposition, and tube fouling may limit NO_x reductions to approximately 50 percent. In addition, operational and environmental impacts of NH_3 emissions and ammonium bisulfate formation could further limit the performance of the process and affect its applicability. These limitations are best evaluated in a full-scale demonstration. Total operating costs are estimated between 0.27 and 1.23 mills/kw-hr exclusive of license fee. Actual costs depend primarily on boiler size, initial NO_x concentration, and level of control required. This assessment also considered the impact of widespread process implementation on the ammonia market, feedstock supplies, and their costs. These impacts were found to be small.

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SECTION 1

INTRODUCTION

Noncatalytic reduction of NO_x emissions by ammonia injection is a very effective technique for stationary source NO_x control. This technique, patented by Exxon Research and Engineering (ER&E) Co., and known as Thermal $DeNO_x$, is operational for gas- and oil-fired boilers. However, demonstration of Thermal $DeNO_x$ with coal-fired systems has so far been limited only to a pilot-scale plant.

The Thermal $DeNO_x$ Process is more expensive than conventional combustion modifications for NO_x controls. Therefore, the process is most attractive as a supplement to combustion modification to achieve stringent emission levels.

Current and projected New Source Performance Standards (NSPS) for NO_x emissions for utility and large industrial steam generators will probably not require the use of the Thermal $DeNO_x$ Process. In the forseeable future, NSPS for these sources will be based on conventional combustion modifications for all fuels. However, there is a need for the process in certain Air Quality Control Regions (AQCR) for attainment and maintenance of the National Ambient Air Quality Standard for NO_2 (NAAQS) (100 $\mu g/m^3$, annual average). For example, in the Los Angeles South Coast Air Quality Management District, conventional combustion modifications are already being implemented to near maximum extent on

utility boilers. Nonetheless, the annual average NO_2 ambient standard is being exceeded. State and local regulating groups are recommending Thermal $DeNO_x$ for utility boilers to aid in attainment (Reference 1-1).

There appears to be a further need for Thermal $DeNO_x$ for maintenance of the annual average NAAQS in other Air Quality Control Regions. Projections of source emissions and ambient air quality into the 1980's and 1990's show a need for stringent controls -- comparable to Thermal $DeNO_x$ -- in several AQCR's (Reference 1-2 and 1-3). These stringent controls will be needed to offset source growth particularly with the increased use of coal in new and existing sources.

In addition to attainment and maintenance of the annual average NAAQS, Thermal $DeNO_x$ may well be needed to attain the impending short term NO_2 ambient standard. This standard, required by the 1977 Clean Air Act Amendments, is still in preparation. However, preliminary calculations show a need for stringent NO_x control for selected point sources to prevent "hotspot" violations of a one hour standard (Reference 1-3).

Furthermore, the non-attainment provisions of the recent Clean Air Act Amendments of 1977 require individual States to assure attainment of air quality standards for NO_2 by requiring Lowest Achievable Emission Rates (LAER) for new sources, in non-attainment areas. LAER is defined as the lowest emission rate achievable in practice by that category of sources and presumably would include Thermal $DeNO_x$.

Based on the above considerations there is a definite need for stringent NO_x control from coal-, oil- and gas-fired utility boilers. The Thermal $DeNO_x$ Process seems to be the only economic alternative control technique which could guarantee 40-50 percent NO_x reductions beyond the percent controlled levels from gas- and oil-fired utility

boilers. However, in the absence of a full-scale demonstration the technology is not considered commercially available for coal-fired units. Numerous operational and economic aspects of injecting ammonia in the severe flue gas environment derived from coal combustion need evaluation.

Exxon Research and Engineering Company (ER&E) has recently performed an economic and technical assessment for the EPA for retrofit of coal-fired utility boilers with ammonia injection. Exxon's effort was directed primarily at evaluating the performance of the process on typical coal-fired steam generator designs and to estimate the process cost to the utilities for retrofitting and operating the ammonia injection system.

The work presented in this report was performed in parallel with Exxon's. The objectives of the study were to critique Exxon's results and to conduct an independent assessment of ammonia injection for coal-fired utility boilers. The effort was directed primarily at three areas:

- Past Experience: A literature review of current open literature in which laboratory, pilot- and full-scale data from use of ammonia injection with gas, oil, and coal firing are presented (Section 2),
- Applicability Study: Assessment of the results of the Exxon study on the applicability of this technology for coal-fired utility boilers (Section 3),
- Cost Analysis: An analysis of how boiler capacity and design, affect the cost of ammonia (NH_3) injection as a control technique on coal-fired utility boilers (Section 4).

The following sections discuss results of the assessment of each of these areas.

REFERENCES FOR SECTION 1

1-1. "Public Hearing of Rule 475.1 of the South Coast Air Quality Management District," State of California Air Resources Board, Docket No. 78-10-1, April 25, 1978.

1-2. Mason, H. B., et al., "Preliminary Environmental Assessment of Combustion Modification Techniques: Volume II. Technical Results," EPA-600/7-77-119b, NTIS-PB 276 681/AS, October 1977.

1-3. Waterland, L. R., "Environmental Assessment of Stationary Source NO_x Control Technologies -- Second Annual Report," Acurex Report TR-78-116, July 1978.

SECTION 2

PAST EXPERIENCE

The noncatalytic reduction of NO by the Thermal DeNO$_x$ Process was discovered in August 1972 by Exxon Research and Engineering Co. (ER&E). Since then, numerous laboratory, pilot, and full-scale tests have further investigated the Thermal DeNO$_x$ Process. These tests have been designed to understand the critical process parameters and how they can be used to control NO$_x$ emissions from both stationary and mobile sources.

ER&E, developer of the Process and patent holder, has done most of the laboratory research and field studies. However, Exxon's tests were limited to gas- and oil-fired facilities, except for full-scale tests on a solid waste incinerator. KVB Inc., under contract to ER&E and EPRI has recently studied the use of Thermal DeNO$_x$ on a 3×10^6 Btu/hr coal-fired test boiler. KVB has also conducted the only domestic full-scale application of NH_3 injection. This was on a thermal oil recovery steam boiler.

Table 2-1 presents a summary of all commercial installations utilizing noncatalytic decomposition of NO$_x$ by ammonia. All of these installations use Exxon's ammonia injection technology except for one Japanese source noted. Detailed information on all installations using Exxon's Thermal DeNO$_x$ Process is not available. However, depending on the source and its operation, NO$_x$ reductions as high as 70 percent have been achieved.

TABLE 2-1. SUMMARY OF COMMERCIAL APPLICATIONS OF EXXON'S THERMAL $DeNO_x$ PROCESS

Source	Fuel Burned	Location	Initial Nitric Oxide Emissions (ppm as measured)[a]	$DeNO_x$ Rate (Percent)	Additive[b]	Comments
Steam Boiler 45 MW heat input	Gas/oil	Japan	120-150	60	Yes	No reduction obtained at full load
Incinerator 7 ton/hr	Waste	Japan	100-180	20-70	NA[c]	Difficult source to retrofit because of constant change in fuel
Crude heater 150 x 10^3bbl/day	Gas/oil	Japan	150	35-65	Yes	Best reductions achieved at high load
Steam boiler 76 MW heat input	Gas/oil	Japan	95-145	35-50	NA	No details of retrofit system are available
Utility boiler 275 MW heat input	Gas/oil	Japan	80-120	60	NA	No details of retrofit system are available
Utility boiler 275 MW heat input	Gas/oil	Japan	80-120	50-60	NA	No details of retrofit system are available
Crude heater 150 x 10^3bbl/day	Gas/oil	Japan	80-85	40-65	NA	Best reductions achieved at high loads
Thermal recovery heater	Oil	USA-California	260	50-70	NA	First commercial U.S. installation
Utility boiler 375 MW	Residual oil	Japan	NA	40	No	Does not use Exxon NH_3 injection technology -- NH_3 emission limited to 10 ppm

[a]Excess oxygen varied between 3-5 percent for all sources
[b]"Yes" indicates that hydrogen was injected together with NH_3 to obtain reported NO_x reduction performances
"No" indicates that no additive was used
[c]NA = no data are available

Based on these full-scale results, Exxon has commercialized the process and will license it upon request on gas- and oil-fired boilers. Additionally, they are continuing to study the feasibility of full-scale applications on coal-fired boilers. These studies are aimed at maximizing NO_x reduction and cost effectiveness, and exploring and defining potential operating problems.

This section summarizes the status of Thermal $DeNO_x$ Process developments. Results from gas and oil combustion in laboratory and pilot-scale studies are discussed in Section 2.1. Section 2.2 presents results from ammonia injection in a coal-fired pilot-scale facility. Results from ER&E's full-scale commercial demonstration of the process are described in Section 2.3.

2.1 SUBSCALE TESTING -- GAS AND OIL

ER&E discovered a new reaction which is the basis of the Process in research done in a laboratory flow reactor. Based on the observed kinetics of this reaction Lyon proposed the following mechanism (Reference 2-1):

$$NH_2 + NO \longrightarrow N_2 + H + OH$$

$$NH_2 + NO \longrightarrow N_2 + H_2O$$

$$H + O_2 \longrightarrow OH + O$$

$$O + NH_3 \longrightarrow OH + NH_2$$

$$OH + NH_3 \longrightarrow H_2O + NH_2$$

$$H + NH_3 \longrightarrow N_2 + NH_2$$

To further explore this reaction mechanism, ER&E conducted tests on a small 0.3 MW (10^6 Btu/hr commercial size boiler). These tests investigated how key operating variables such as reaction temperature,

NH_3 injection rate and flue gas residence time influence the NO_x reduction effectiveness.

Additional tests were conducted on a 9 MW (30×10^6 Btu/hr) test furnace to optimize mixing and injection methods and to evaluate problems such as corrosion and fouling which may be encountered during full-scale application. ER&E also evaluated the economics of full-scale application of the process for oil- and gas- firing. KVB Inc. has also considered the effects of Thermal $DeNO_x$ on key operating parameters. Both ammonia and a proprietary ammonia-based compound were investigated as NO reducing agents for product gases from the combustion of gas and oil.

The Exxon and KVB test results reveal the following key operating variables and constraints which affect the efficiency of the Thermal $DeNO_x$ Process:

- Reaction temperature
- Ammonia injection rate
- Mixing technique and reaction time
- Hydrogen and other additive injection
- Byproduct and ammonia emissions

The following sections briefly describe these key parameters and their effects on the $DeNO_x$ Process.

2.1.1 Reaction Temperature

The temperature of the flue gas at the point of NH_3 injection is a key process condition because the reaction between NO and NH_3 in the presence of O_2 is extremely temperature sensitive, i.e., the temperature range in which ammonia is effective in reducing NO concentrations is small. This characteristic, therefore, governs how the process can be applied.

Lyon reported that the reaction temperature of about 955°C (1750°F) results in the largest NO reduction. At temperatures higher than approximately 1100°C (2010°F), the oxygen present in the flue gas oxidizes the injected ammonia producing a net increase in NO. Below 900°C (1650°F), the reaction of NH_3 with NO is slowed considerably causing less NO reduction and more NH_3 emission from unreacted gases. Figure 2-1 shows how the reaction temperature affects the performance of the Thermal $DeNO_x$ Process.

This strong dependence of Thermal $DeNO_x$ performance on reaction temperature can limit the use on some systems. For example, the required temperature window in gas turbines and IC engines is located where a very short residence time is available for reaction with NH_3. Thus, Thermal $DeNO_x$ may not be suited to these sources. In large steam generators, the optimum temperatures and residence times for noncatalytic reduction of NO are usually accessible in the boiler convective section. However, cross-sectional temperature gradients as high as 200°C (360°F) often exist making ammonia injection considerably less effective for some areas of the flue gas ducts. Load variations also shift the temperature profile causing the temperature window to move in the convective section.

These problems could theoretically be solved by installing more than one injection stage to account for the shift in the temperature window. However, additives have also been evaluated as methods to accommodate temperature variations and unfavorable location of the temperature window. For example, hydrogen additive is a demonstrated alternative for controlling or shifting the injection points to the optimum temperature location for the Thermal $DeNO_x$ Process. Additive injection is discussed in Section 2.1.3.

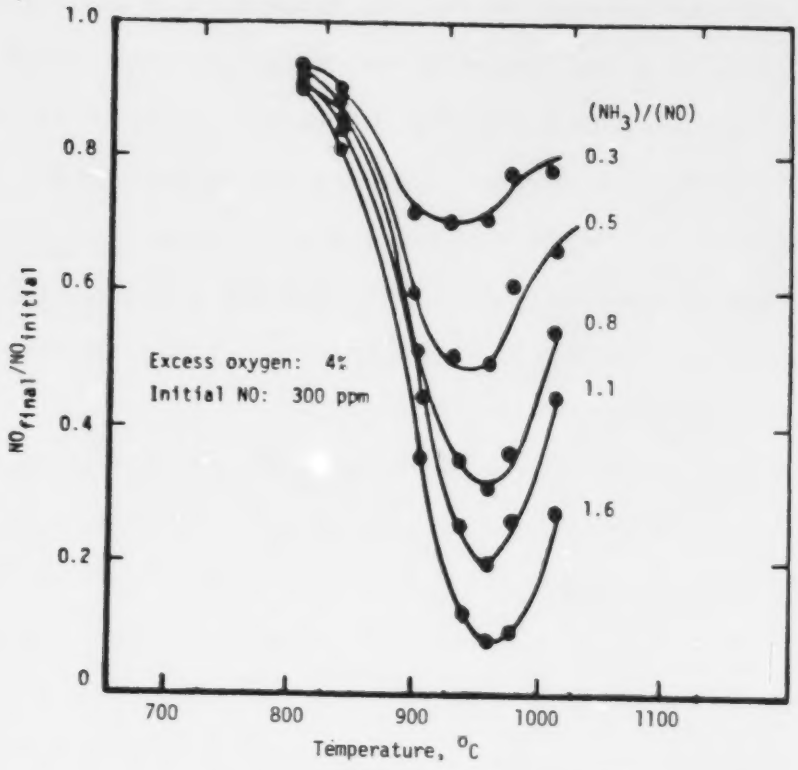

Figure 2-1. Effect of flue gas temperature on Thermal $DeNO_x$ performance (Reference 2-2).

2.1.2 Ammonia Injection Rate

Ammonia efficiently reduces NO_x because of its ability to react selectively with nitric oxide regardless of the amount of oxygen present in the treated gas. Thus, the amount of ammonia required in the Thermal $DeNO_x$ Process is on the order of the initial NO concentration. Other additives, such as methane and ethane also can be used to reduce NO in hot flue gases. However, because these reagents are nonselective, they do not react with nitric oxide alone. That is, all the free oxygen present in the hot gases must first be consumed by the reagents before the NO can be reduced. Therefore, more hydrocarbons are necessary, thus causing these additives to be economically unattractive.

Experiments conducted by ER&E and KVB show that for typical conditions, an ammonia injection rate of 2.0 (molar ratio of NH_3 to initial NO concentration, (NH_3/NO)) achieves the optimum maximum process efficiency. Figure 2-2 shows that minimal additional NO reduction is obtained by increasing the ammonia injection rate beyond the NH_3/NO molar ratio of 2.0.

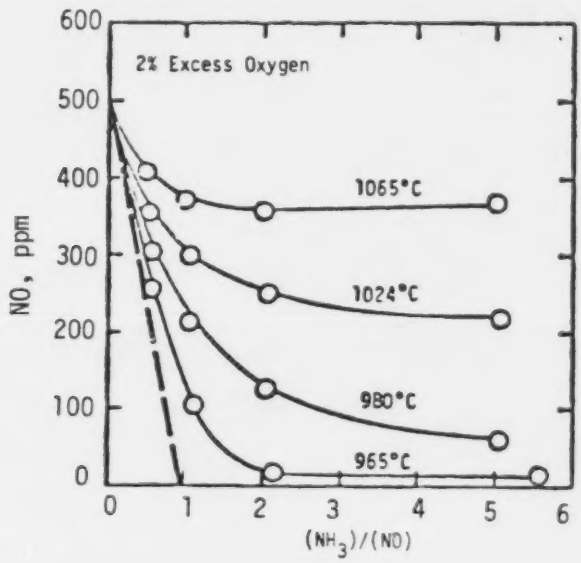

Figure 2-2. Effect of NH_3 injection rate on NO emissions (Reference 2-2).

Ammonia injection rates depend on the initial concentration of nitric oxide. Experimental data illustrated in Figure 2-3 show that lower molar ratios of NH_3/NO are needed to achieve a given process efficiency when the initial NO concentration is greater than 400 ppm. These experimental data further indicate that the percent oxygen in the flue gas may also have some effect on required NH_3 injection rates. Minimum amount of dilution with excess air decreases the volume of flue gas to be

treated and increases initial NO concentration thus possibly reducing the amount of NH_3 needed.

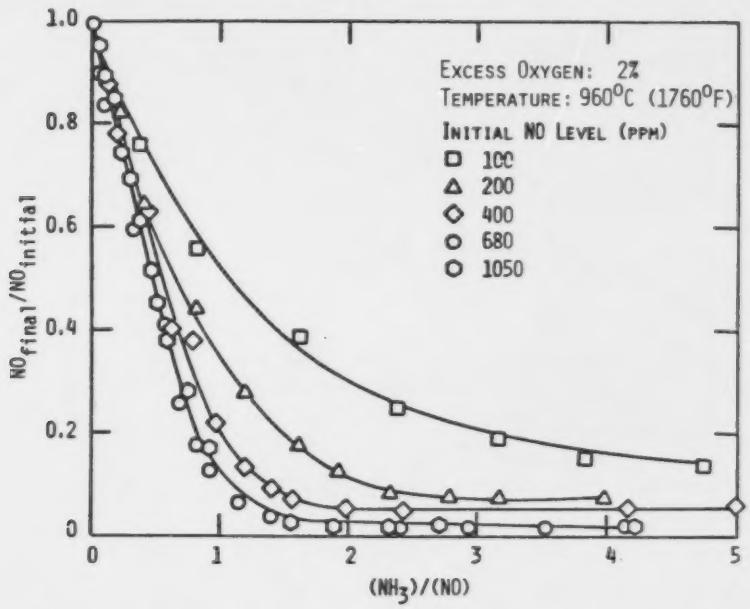

Figure 2-3. Effect of initial nitric oxide concentrations on reductions with ammonia injection (Reference 2-2).

The ammonia injection rate, the reaction temperature and the residence time are critical in maintaining ammonia emissions at minimum levels. Test data depicted in Figure 2-4 indicate that the level of unreacted ammonia at the injection temperature of 965°C (1770°F) increases significantly only at NH_3/NO ratios greater than 2.0, as expected. When the reaction temperature is lowered to 870°C (1600°F) the level of ammonia carryover is substantially increased because of the slower chemical reaction. Therefore, the ammonia emission level can be controlled by allowing the reaction to occur at slightly higher temperatures than the optimum 955°C (1750°F). In fact, NH_3

injection, at temperatures above 1000°C (1830°F) virtually all NH_3 breakthrough is eliminated.

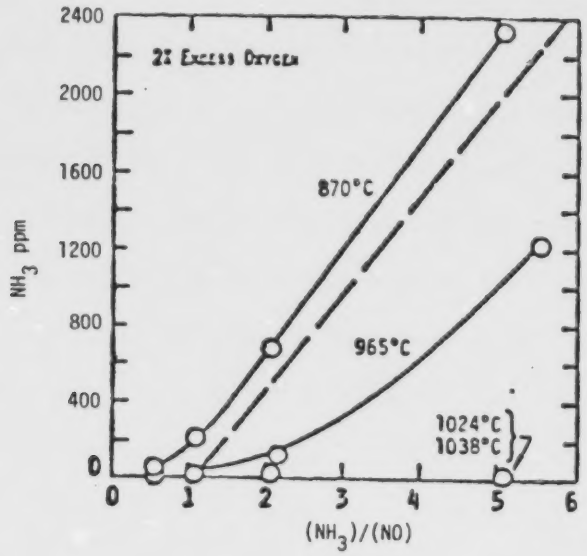

Figure 2-4. Effect of NH_3 injection rate on NH_3 carryover emissions (Reference 2-2).

Poor mixing of ammonia with the flue gas may cause ammonia carryover to occur also at NH_3/NO molar ratios much lower than 2.0. In fact, large scale applications of the Thermal $DeNO_x$ Process have shown that NH_3/NO ratios in nonideal gas conditions generally should be lower than 1.5 to maintain minimum NH_3 emissions. High levels of ammonia breakthrough were caused by high ammonia injection rates combined with ineffective mixing or low flue gas temperatures.

In summary, NH_3/NO molar ratios can vary from 1.0 to 2.0 in large scale applications of the Thermal $DeNO_x$ Process. The actual injection rate used will depend on the desired NO_x reduction and could be limited by ammonia breakthrough. Therefore, the injection rate is the result of

an optimization performance study taking into account flue gas conditions and source configurations.

2.1.3 Hydrogen and Other Additives

The Thermal DeNO$_x$ Process can be applied over a greatly widened range of temperatures if certain additives are injected with the ammonia. Of the many additives investigated, hydrogen is the most effective over the temperature range from 700 to 1010^{o}C (1290 to 1850^{o}F). Figure 2-5 shows the shifting effect of hydrogen injection on optimum reaction temperature measured in a commercial size firetube boiler. The magnitude of this shift depends on the amount of H_2 injected relative to the NH_3. For example, at H_2/NH_3 molar ratios on the order of 2:1 selective noncatalytic reduction of NO_x can be made to occur at 700^{o}C (1290^{o}F). Thus, by carefully selecting the H_2 injection rate, flue gas treatment can be controlled over a wide temperature range.

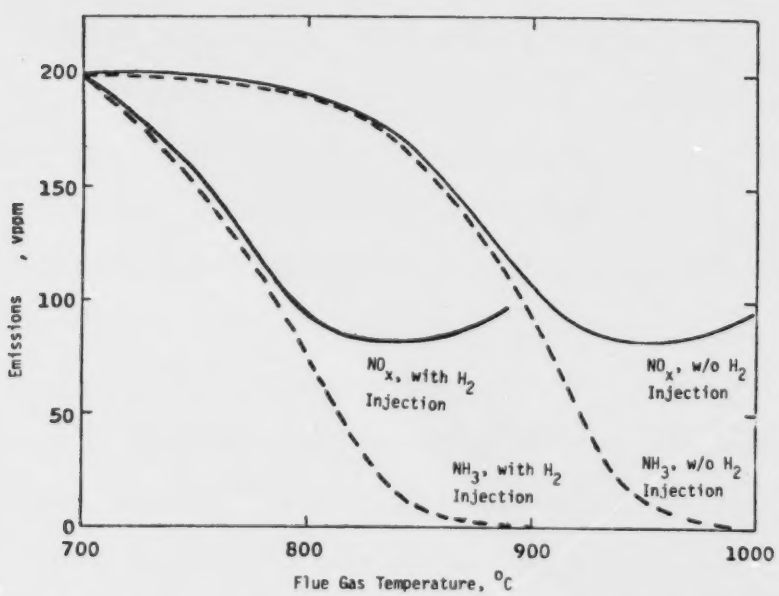

Figure 2-5. Thermal DeNO$_x$ reaction products as functions of temperature with and without hydrogen injection (Reference 2-3).

Exxon also investigated the use of combined additives. A mixture of 50 percent hydrogen and 50 percent methane was found to be more effective than either hydrogen or methane alone. However, the introduction of methane in combustion gases, especially at low excess air levels, increased cyanide emissions by a few ppm.

Additive injection can also be used to control ammonia breakthrough emissions to concentrations lower than 10 ppm. For example, small amounts of H_2 injection with ammonia would lower the optimum reaction temperature from 955°C (1750°F) to 945°C (1733°F). This 10°C (18°F) temperature differential is sufficient to deplete some excess NH_3 which would otherwise exit from the stack.

Because H_2 can control the temperature of the NH_3-NO-O_2 reaction, Thermal DeNO_x is technic feasible for most boilers provided that the hardware can be installed within the boiler configuration. However, the cost of the DeNO_x Process is greatly increased because of the large volumes of hydrogen needed. This is especially the case for very low temperature such as 760°C (1400°F).

Until recently, the NH_3 injection was limited to boiler cavities. Thus if the optimum reaction temperature of about 955°C did not occur in an isothermal cavity, NH_3 was injected at temperatures below this level. This situation warranted the use of an additive to maximize the efficiency of the DeNO_x Process. The in-tube bank injection of NH_3, recently demonstrated by Exxon, has diminished the dependence of the process efficiency on the use of an additive. DeNO_x rates of 60 to 70 percent were achieved by injecting NH_3 in tube banks without the use of an additive.

2.1.4 Byproduct Emissions

The Exxon Thermal $DeNO_x$ Process may form byproduct pollutants directly or indirectly from the presence of NH_3 in the combustion gas. Potential byproduct emissions suggested by ER&E are NH_3, CO, HCN and N_2O and, when sulfur-bearing fuel is burned, NH_3 and SO_3 combine to form ammonium bisulfate, NH_4HSO_4.

Ammonium bisulfate is a viscous liquid from 147°C to about 450°C (300-840°F). It has been known to cause corrosion of metal surfaces. Thus far, however, no increase in metal corrosion attributable to ammonium bisulfate has been identified when Thermal $DeNO_x$ has been used. The formation of NH_4HSO_4 can be controlled by limiting the amount of NH_3 carryover. This can be accomplished by NH_3 injection at a temperature slightly higher than optimum or by using an H_2 additive. In general, ammonium bisulfate is considered the most serious byproduct and one which could effect the use of the Thermal $DeNO_x$ Process.

Carbon monoxide emissions may also be promoted by ammonia injection because the Thermal $DeNO_x$ reaction inhibits the oxidation of CO to CO_2. Thus, if there is unburned CO at the point of NH_3 injection, the CO may not be oxidized, but will be discharged to the atmosphere. Under normal operating conditions, CO levels are not usually significant in steam generators. Using hydrocarbons as additives to control the NH_3-NO-O_2 reaction increases the concentration of CO in the flue gas. Exxon reported that as much as 50 percent of the hydrocarbons may be oxidized to CO. This CO may then be emitted to the atmosphere because the ammonia inhibits the $O_2+CO \longrightarrow CO_2$ reaction.

HCN is formed only if hydrocarbons are present in the region in which NH_3 is injected. Under normal boiler operation, gaseous

hydrocarbons are not present unless they are injected along with the NH_3. KVB reported that for gas, oil and coal firing, HCN was present in the untreated flue gas at 3 to 10 ppm concentration, depending on excess air level. Injection of NH_3 did not measurably affect the HCN level.

The reduction of NO by NH_3 and O_2 forms N_2O as a minor byproduct. However, less than 2 moles are generated for every 100 moles of NO reduced, according to ER&E experimental data. All the available evidence indicates that N_2O is relatively harmless at those levels, and does not represent an environmental concern.

2.2 SUBSCALE TESTING -- COAL

Recently, KVB has conducted a pilot-scale investigation of the Thermal DeNO$_x$ Process to reduce NO levels from combustion of coal (Reference 2-4). The work was sponsored by the Electric Power Research Institute (EPRI) and Exxon Research and Engineering (ER&E).

The major objective of this investigation was to determine the level of NO_x reduction which is achievable in flue gas resulting from coal combustion. The primary variables investigated were the injection temperature, the NH_3/NO ratio, and the coal type. Additionally, a hydrogen additive was used to lower the temperature range for NO removal. Four different coals were investigated; three coals were bituminous and one subbituminous. Byproduct emissions were also measured at different NH_3 injection rates.

The combustion facility consisted of a 0.9 MW (3×10^6 Btu/hr) firetube boiler equipped with a ring-type natural gas burner and a scaled down version of a commercial coal burner presently used in utility boilers firing Western coal. The NH_3 injection system consisted of five

injectors located at the end of the firetube section distributing the ammonia and nitrogen (carrier gas) counter-flow to the flue gas stream. The injectors were designed to be movable so that they could be positioned axially along the length of the firebox thus providing for evaluation of the effectiveness of different temperature profiles. The injection method was a result of an optimization study in which the injection grid and nozzles were designed to provide substantial NO_x reductions that allowed a valid comparison between the various coal types and natural gas. Since the injection method directly affects the efficiency of the Thermal $DeNO_x$ Process, the results achieved by KVB do not necessarily represent the maximum NO_x reductions achievable with coal combustion.

This section discusses the results of this investigation. These results can be used to compare noncatalytic NO reductions and byproduct emissions between coal and the gaseous and liquid fuels previously investigated. Key parameters considered here are again:

- Reaction temperature
- Ammonia injection rate
- Hydrogen and other additive injection
- Byproduct emissions

2.2.1 Reaction Temperature

The temperature at which ammonia is injected into the flue gas is the primary variable which determines the amount of NO removed with the Thermal $DeNO_x$ Process. A major objective of the KVB study was to determine whether the additional pollutants resulting from combustion of coal, such as SO_2 and particulates, would influence the temperature dependence of the process or reduce the process efficiency. Figure 2-6 shows the effect of reaction temperature on NO reduction for the four

coals tested and for natural gas. Since temperature gradients as high as 120°C (216°F) existed radially on any one plane, an average radial temperature was determined. The data in Figure 2-6 indicate that the temperature at which the highest NO reduction occurs varies from 940 to 1000°C (1724 to 1832°F).

It was speculated that the higher sulfur content of the Illinois coal might have caused the maximum NO_x reduction to occur at a higher temperature. Consequently, tests were conducted in the same furnace

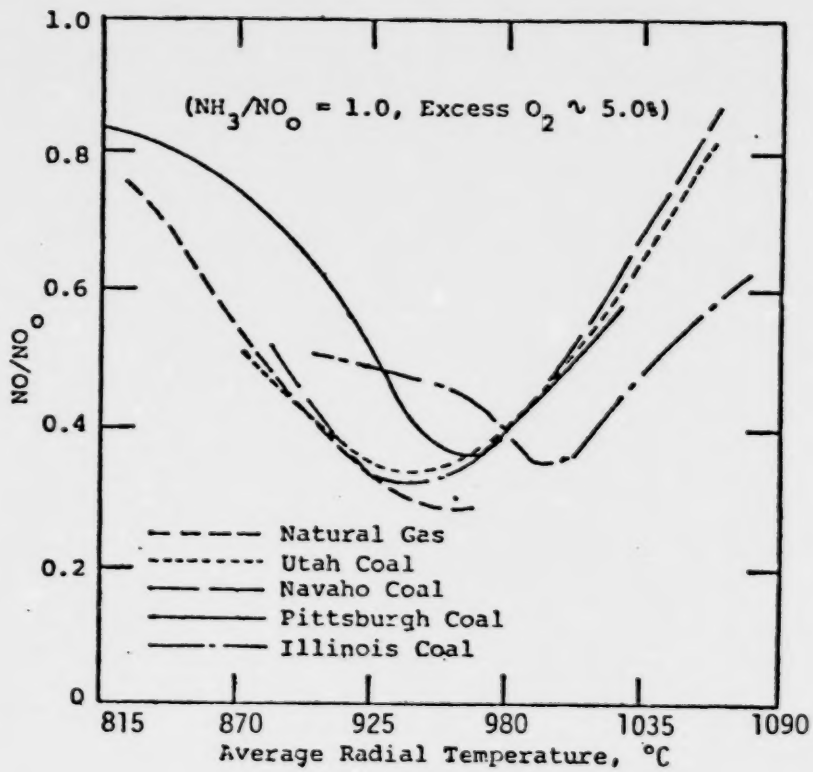

Figure 2-6. Effect of temperature on NO reductions, coal and natural gas firing (Reference 2-4).

furnace in which a sulfur compound was injected into a flue gas generated from distillate oil combustion. The results of this experiment, shown in Figure 2-7, demonstrated that sulfur dioxide has essentially no effect on the reaction temperature required for peak NO_x reduction with ammonia injection. However, more experimental testing with coal combustion might be warranted to confirm or disprove any trends of reaction temperature with coal type. Such experiments are currently in progress at ER&E.

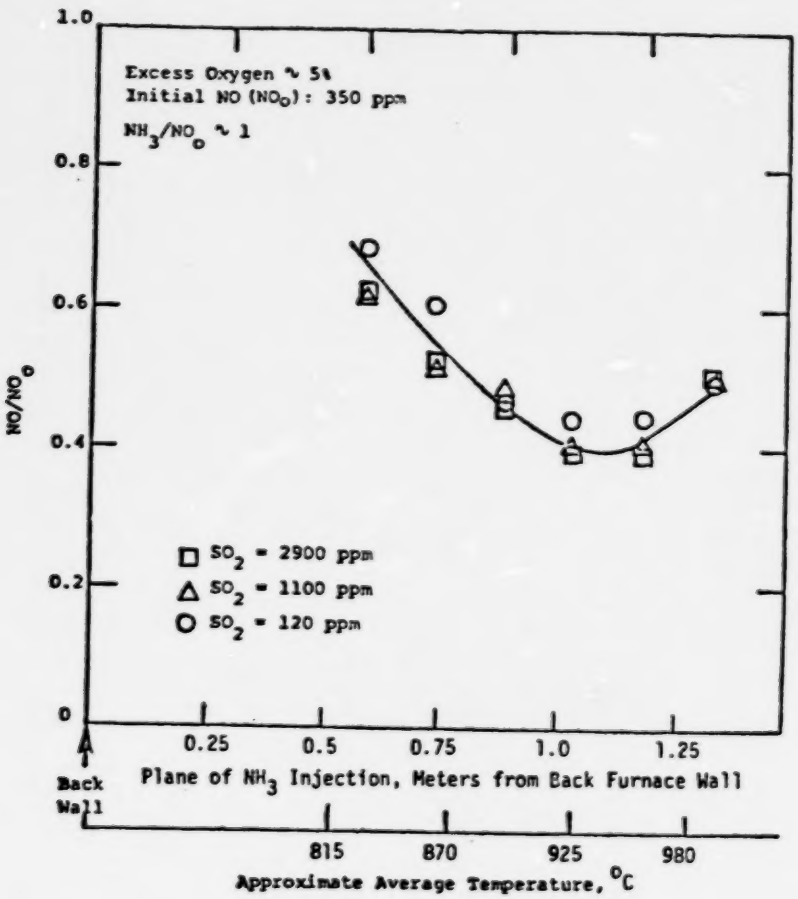

Figure 2-7. Effect of sulfur on NO reduction, oil firing (Reference 2-4).

2.2.2 Ammonia Injection Rate

The effect of ammonia injection rate on NO reduction at peak reduction temperatures is shown in Figure 2-8 for all the fuels tested. KVB attributed the scatter in the data to variations in radial temperature and to ash accumulation in the firebox which hindered temperature measurements. The data show that the NO reduction becomes quickly asymptotic to the 80 percent level. This maximum ammonia injection efficiency is reached at a NH_3/NO molar ratio of approximately 1.5. Very little additional NO reduction is achieved by increasing the NH_3 injection rate to 2.0.

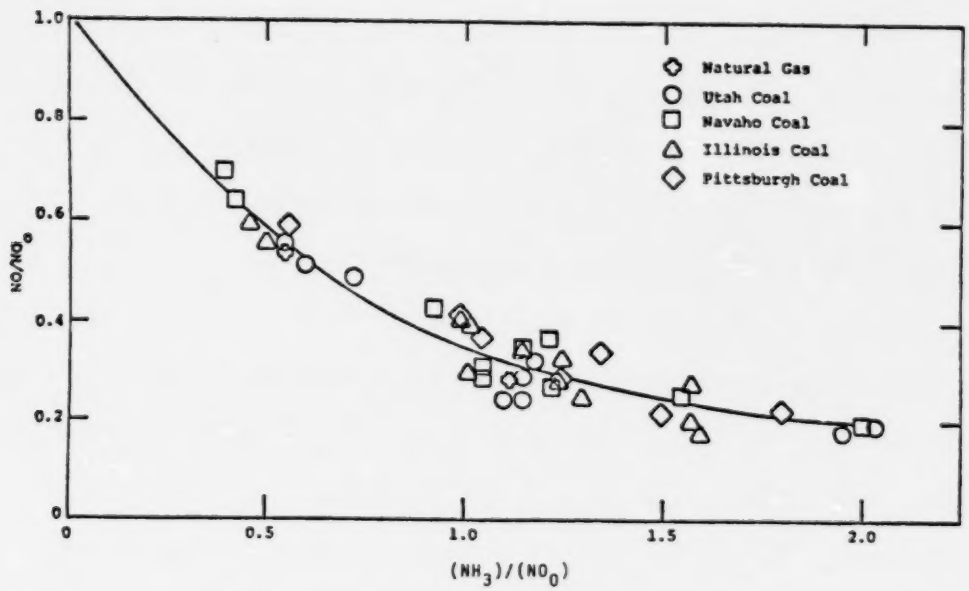

Figure 2-8. Comparison of NO reductions at the optimum temperature condition (Reference 2-4).

2.2.3 Hydrogen Injection

A limited number of tests were conducted with combined NH_3-H_2 injection. These tests included only the combustion of the Pittsburgh Seam No. 8 bituminous coal. Combined injection of NH_3-H_2 produced higher NO reduction at temperatures lower than the optimum 950°C. Maximum $DeNO_x$ rates were maintained over a temperature range of 760°C to 950°C by injection of H_2 at a rate ranging from 0.2 to 0.94 measured as the molar ratio of H_2 to NH_3. The injection of hydrogen also contributed to lower NH_3 breakthrough. KVB found that at high hydrogen injection rates, NO levels increase while NH_3 levels in the combustion products decrease.

2.2.4 NH_3 and Byproduct Emissions

Ammonia emissions are an important consideration in evaluating the $DeNO_x$ Process for coal combustion. The importance of this consideration depends on the amount of NH_4HSO_4 which may be formed by the NH_3 + SO_3 + H_2O reaction. This in turn depends on the amount of SO_3 in the flue gas which is related to the type of coal being fired and the level of excess air. For example, subbituminous coals, such as Navaho, contain calcium, and yield strongly basic flyash which tend to remove SO_3. In fact, KVB reported only small amounts of SO_3 in the flue gas, 5 ppm, with combustion of this coal. Bituminous coals, such as the Illinois or Pittsburgh, however, yielded a flue gas containing up to 21 ppm of SO_3. Therefore high sulfur content coals will produce high levels of sulfur oxides emissions which in time may react with the free ammonia to form ammonium sulfates, an undesirable byproduct. Figure 2-9 shows that for all coals except the Illinois coal, NH_3 emissions increased when the injection rate was greater than 0.5 NH_3/NO. No explanation was

given for the lower NH_3 emissions with Illinois coal firing. However, the higher optimum temperature when firing Illinois coal probably contributed to the low NH_3 breakthrough.

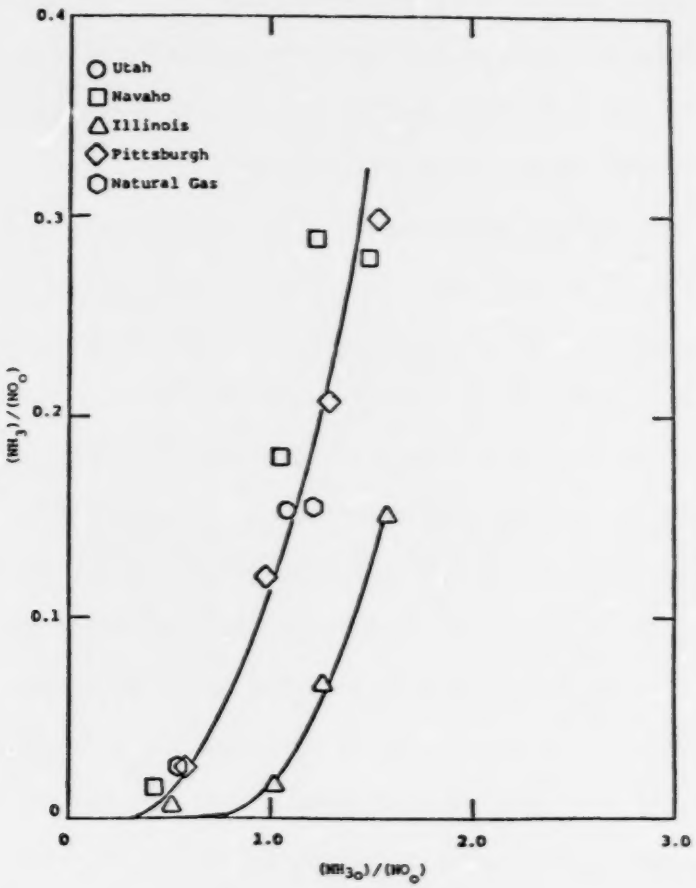

Figure 2-9. Comparison of the NH_3 emissions for all fuels tested at the peak NO removal temperature (Reference 2-4).

KVB investigated the use of H_2 injection to maintain NH_3 emissions at a minimum. Results from this investigation showed that NH_3 emissions decreased nearly 90 percent when H_2 was injected at a rate of 2.0 (measured as molar H_2/NH_3). The NH_3 injection rate (measured as molar NH_3/NO) was approximately 1.5 during these tests.

Cyanide and nitrate emissions were measured by KVB during the combustion of all the coals and natural gas. Emission levels averaged 2 ppm for cyanide and approximately 10 ppm for nitrates at baseline and with reduced NO_x conditions. No correlation was observed between the amount of ammonia injected and the emission levels of these pollutants. These results indicate that cyanide and nitrate emissions are not a byproduct of the ammonia injection process.

Sulfate and SO_3 emissions were also measured during the KVB tests. Since sulfate emissions increased on two tests, but decreased on two others, no conclusions could be drawn. Slight decreases in SO_3 emissions during NH_3 injection were observed, indicating that SO_3 was not proportional to the amount of ammonia present in the flue gas.

CO emissions increased when ammonia was injected to reduce NO_x, but this increase was limited to 50 ppm for Pittsburgh coal. In general, the results indicated that, reducing NO levels through noncatalytic reaction with ammonia inhibits the oxidation of CO to CO_2. However, the CO levels were not considered to be environmentally significant or detrimental to the efficiency of a coal-fired utility boiler.

Results from measurement of SO_2 emissions were inconclusive because sampling problems were experienced during these measurements. These problems were caused by a loss of SO_2 in the sampling lines occurring only when ammonia was injected in the flue gas. The loss of SO_2 was attributed to an absorption - desorption process on the Teflon line rather than a process occurring in the boiler.

2.3 COMMERCIAL APPLICATION

After completing and evaluating the gas and oil subscale tests, but before the coal subscale tests, ER&E tested the Thermal DeNO$_x$ Process on

a 45 MW heat input (70 ton/hr) oil-fired steam boiler, located at Exxon affiliates in Kawasaki, Japan. During 1975 and 1976, seven additional full-scale units were retrofitted with the Thermal DeNO$_x$ Process. These units consist of two 275 MW heat input (430 ton/hr) high pressure oil-fired utility boilers, two pipestill furnaces rated at 150 x 10^3 bbl/day, a 7 ton/hr solid waste municipal incinerator, a 76 MW heat input (120 ton/hr) gas- and oil-fired steam boiler, and a 375 MW oil-fired utility boiler.

All these sources are located in Japan where NO$_x$ emissions regulations are much more stringent than in the United States. In addition to these sources, one full-scale application of the process was conducted in California on a thermal oil recovery boiler. Not all information on this sole domestic application is proprietary. NO$_x$ reductions of 60 and 70 percent have been disclosed (Reference 2-5).

In all these applications, the effectiveness of the DeNO$_x$ Process depended on the design configuration of the unit and the flue gas conditions at the selected injection point. Figure 2-10 shows the performance of the process on commercial installations as a function of the flue gas temperature. The performance of the noncatalytic ammonia injection system on the 375 MW utility boiler is not included. However, 40 percent efficiency has been reported (Reference 2-7). The performance data in Figure 2-10 were obtained based on maximum NO$_x$ reduction while maintaining NH_3 breakthrough at a minimum. It can be seen that at approximately 950^{o}C (1740^{o}F) optimum injection temperature, the maximum NO$_x$ emission reduction was about 60 percent. The performance of the process decreased at lower flue gas temperatures even though hydrogen was injected in some cases to shift the optimum temperature.

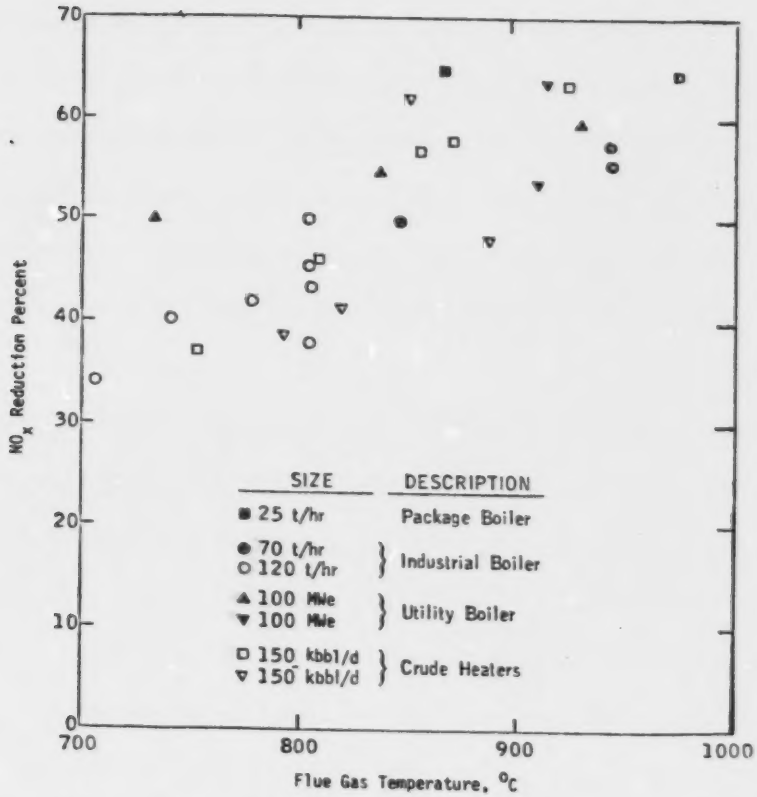

Figure 2-10. Thermal $DeNO_x$ system performance on commercial units as functions of temperature (Reference 2-6).

Long term corrosion tests on the 45 MW boiler have shown that after 1100 hours of continuous operation, boiler tube corrosion was not significantly higher with ammonia injection than with uncontrolled operation. However, because the regenerative preheater was fouled by ammonia sulfate deposits, the tubes required washing at periodic intervals.

In summary, the Thermal $DeNO_x$ Process has been demonstrated to be approximately 60 percent effective in full-scale applications over a 200°C temperature range without major operational problems. Although these results are restricted to oil and gas units, the process has also been successfully demonstrated on a solid waste incinerator.

The process is subject to several limitations primarily resulting from nonideal gas conditions. Nonideal gas conditions are due to lack of cavities at desired injection temperatures and the presence of temperature gradients at any one injection location. Nonuniform gas velocities also limit the efficiency of the system unless sophisticated injectors are devised.

The recently concluded work on NH_3 injection in tube banks indicates that the process can also achieve NO_x reduction comparable to cavity injection. Therefore, since Thermal $DeNO_x$ is not restricted to injection in boiler cavities, it becomes adaptable to nearly all types and sizes of steam generators. The maximum demonstrated efficiency is, however, currently limited to approximately 60 percent due to nonuniformity of gas velocities and temperatures found in the flue gas of boilers.

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SECTION 3

APPLICABILITY ASSESSMENT

The Exxon's Thermal $DeNO_x$ Process can reduce NO_x emissions by 40 to 60 percent for gas- and oil-fired boilers. Performance of the $DeNO_x$ technique can be equal to or better than conventional combustion modifications. However, operating cost of the NH_3 injection is much higher than combustion modifications. Hence, the process is most cost-effective when used in conjunction with combustion modifications. Specifically, the combined effect of NH_3 injection with conventional controls is considered a viable technique for boilers which cannot meet projected NO_x emissions standards with only conventional controls.

Coal-fired utility boilers are the major source for which the $DeNO_x$ Process has recently been evaluated. The increased use of coal as the main fuel for utilities, combined with the high uncontrolled NO_x levels from coal combustion and the difficulty in reducing NO_x emissions more than 50 percent when using combustion controls alone, make coal-fired sources a prime candidate for Exxon's $DeNO_x$ Process.

Exxon has developed a calculation procedure which can predict $DeNO_x$ performance from all boilers -- including coal-fired ones. The calculation procedure is based on proprietary and published results from pilot- and full-scale investigations. Published reports have been briefly described in Section 2.

Using this Performance Prediction Procedure, Exxon has conducted an analysis of the maximum NO reduction achievable in eight typical coal-fired utility steam generators. Exxon also evaluated the combined effects of NH_3 injection with conventional combustion modifications. These calculations estimated whether the added NO reduction from NH_3 injection could reduce NO_x emission levels to 300 ppm for bituminous coal and lignite, and 225 ppm for subbituminous coal regardless of the initial NO emission level.

This section presents an assessment of the applicability of NH_3 injection technology to reduce NO emissions from coal-fired powerplants. This assessment includes:

- Analysis of the correlation scheme and Exxon's predicted results (Section 3.1)
- Review of the process limitations and potential adverse effects (Section 3.2)

This assessment is based primarily on proprietary information furnished by Exxon and supplemented by published data from KVB, Exxon, and EPRI.

3.1 CORRELATION PROCEDURE AND PREDICTED RESULTS

Experimental results using NH_3 injection in flue gas streams have clearly shown that the efficiency of the Thermal $DeNO_x$ Process depends on the NH_3 injection rate, the injection temperature, and the residence time of the flue gas. Based on these results, Exxon has correlated average injection temperature and flue gas residence times with NO_x reductions at various NH_3 injection rates. The correlation accounts for the flue gas being cooled by convective tubes of boilers. Boilers with large cavities in the temperature range of 1000°C to 760°C (1830°F to 1400°F) are most desirable because effective residence times are longer.

The Exxon correlation predicts NO_x reductions as high as 70 percent for long effective residence times and an NH_3 injection rate of $NH_3/NO = 1.5$. However, cross sectional uniformity in flue gas flow and temperature is necessary to achieve these performance levels. Unfortunately, temperature and flow distributions at any one cross section of the boiler are not uniform. The correlation accounts for nonuniformity of flue gas temperature and flowrate. The predicted performance is reduced when corrections reflecting temperature and velocity gradients are applied.

Gradients in NO concentration across the duct of coal-fired boilers may also be present which are not accounted for in the Exxon Performance Prediction Procedure. NO stratification in the ducting of coal-fired powerplants has been measured by Exxon (Reference 3-1). The nitric oxide concentration varied by 19 percent from the average cross sectional value. Even though these measurements were made downstream of the air heaters, it is possible that some NO stratification may also be present at the convective section of large coal-fired boilers where NH_3 would be injected.

If NO stratification was found in most of the boilers, the Exxon correlation would also need to account for this nonuniformity in flue gas conditions in addition to the temperature and flow nonuniformities. Considering temperature, velocity and NO concentration gradients, uniform NH_3 injection may not be feasible if significant system efficiencies are required. Thus, for a retrofit application, the flue gas characteristics at the injection location should be carefully mapped before selecting the system design and operating conditions. A zoned injection system accounting for temperature, velocity and NO concentration gradients may be warranted if large variations exist. Each zone would have its own NH_3

injection rate. Such an injection system would be more sophisticated and thus, more costly.

The Exxon empirical correlation appears to be a useful tool in predicting an approximate NO reduction level achieved with a specific injection system design. However, the procedure will only predict approximate $DeNO_x$ rates unless a detailed characterization of the flue gas temperature, velocity and NO concentration is made at many different loads. Section 3.2 will show that, especially for coal combustion, numerous boiler design operating characteristics will affect actual performance of the Thermal $DeNO_x$ system.

As part of the applicability assessment of the Thermal $DeNO_x$ Process on coal-fired utility boilers, Exxon selected eight coal-fired units and applied the developed correlation to estimate maximum NO reduction (Reference 3-2). The selection of coal-fired boilers included designs from the largest manufacturers of utility steam generators. Two front wall and two horizontally opposed wall boilers manufactured by Babcock and Wilcox (B&W) and Foster Wheeler (FW) were selected. These boiler firing types represent approximately 67 percent of the current installed units (Reference 3-3). Two tangentially fired Combustion Engineering (CE) boilers were also selected. These boilers represent approximately 20 percent of the total installed units in 1974 (Reference 3-3). One cyclone and one turbo/furnace boiler were also selected.

Table 3-1 lists the results of Exxon's performance prediction analysis of the Thermal $DeNO_x$ Process on these boilers. Percent NO_x reductions for the NH_3/NO = 1.0 and 1.5 injection rates were reported by Exxon. However, the percent NO_x reductions for the NH_3/NO = 0.5

TABLE 3-1. SUMMARY OF EXXON PREDICTED THERMAL $DeNO_x$ PERFORMANCE (WITHOUT COMBUSTION MODIFICATIONS)

Unit	Boiler Load % MCR	Initial NO_x ppm	Maximum $DeNO_x$ Rate (percent)			Injection Grid	Injection Location
			$NH_3/NO = 0.5$	$NH_3/NO = 1.0$	$NH_3/NO = 1.5$		
B&W 333 MW	100	500	20	38	48	1	Tube bank
	75	450	20	38	48	1	Tube bank
	50	400	25	49	63	2	Cavity
B&W 333 MW	100	700	24	48	63	1	Cavity
	75	630	22	44	56	2	Tube bank
	50	560	22	44	56	2	Tube bank
B&W 400 MW	100	1000	23	45	57	1	Tube bank
	75	900	23	45	57	1	Tube bank
	50	800	NA_v[a]	NA_v	NA_v		
CE 350 MW	100	500	26	52	58	1	Cavity
	75	450	20	40	45	2	Cavity
	60	400	20	40	45	2	Cavity
CE 800 MW	100	530	25	52	57	1	Cavity
	75	480	20	40	45	2	Cavity
	60	425	20	40	45	2	Cavity
FW 330 MW	100	850	20	41	54	1	Cavity
	75	770	NA_v	NA_v	NA_v		
	60	680	NA_v	NA_v	NA_v		
FW 670 MW	100	700	24	47	60	1	Cavity
	75	630	NA_v	NA_v	NA_v		
	50	560	NA_v	NA_v	NA_v		
RS 350 MW	100	700	24	47	58	1	Cavity
	75	630	NA_v	NA_v	NA_v		
	60	560	22	45	54	2	Cavity

[a]Not available

injection rate were extrapolated using the Exxon Performance Prediction Procedure. Two injection grid locations were selected to account for the boiler heat input levels, 100, 75 and 50-60 percent of design capacity. One grid (dual load) was located to give the best compromise performance at two load levels, while the other grid (single load) was located to give maximum performance at the remaining load level. Often both injection grids were located in boiler cavities. However, on two units, one of the grids was located directly within a tube bank. In this section a boiler cavity is defined as the space between two subsequent tube banks, while in-tube bank injection corresponds to injector grid location directly within a bank of convective tubes. The $DeNO_x$ rates reported in Table 3-1 represent the maximum performance of the process without combustion modifications at the respective NH_3 injection rates as predicted by Exxon.

At first it would seem evident that cavity injection for the B&W wall fired units is more effective than injecting NH_3 directly within a tube bank. However, the difference between the performance of the two injection locations derives from having only two injection grids to maximize NO_x reductions at three boiler loads or three flue gas temperatures. If three injection grids were available, each placed at the desired location, the $DeNO_x$ performance would somewhat improve for the two dual load points.

In retrofit application of the Thermal $DeNO_x$ system, the most frequently used load (baseline load) of the unit should be emphasized in designing injector placement. This is to insure that at least one injection grid will maximize $DeNO_x$ performance at that particular boiler load. That is, if a boiler operates at 90 percent of Maximum Continuous

Rating (MCR) during most of its continuous operation, one injection grid should be located to reduce NO_x emissions at that load.

From a performance standpoint, there is no clear indication that Thermal $DeNO_x$ is more effective with any one boiler design. For equal injection rates NO_x percent reductions are nearly the same for all boilers. However, in the case of NH_3/NO equals 1.5, the performance of the Thermal $DeNO_x$ Process for the two CE units is 3 to 12 percent lower than for the B&W units. This is probably due to their lower initial NO emission levels.

The performance values reported here include only corrections for temperature distribution across the flue gas duct at the injection location. A temperature range over the duct cross section was used by Exxon for the cavity and tube bank segment at the exit of the boiler furnace. For all other downstream cavities and tube bank segments, a lower temperature range was assumed. These temperature ranges were partly suggested by the boiler manufacturers and were partly based on Exxon's field experience. Insufficient data exist to quantify these temperature gradients in wall fired utility boilers and to determine if all significant temperature effects caused by boiler design and operating conditions are accounted for.

Gradients in flue gas velocity and NO concentrations in the cross sectional plane at the injection location were not taken into consideration by Exxon when calculating the performances reported in Table 3-1. These gradients could be large enough to reduce actual performance significantly, in the absence of compensating measures such as NH_3 injection zoning.

3.2 PROCESS LIMITATIONS

The performance of the Thermal $DeNO_x$ Process is limited by the temperature and flow nonuniformities in the flue gas ducts. Exxon's Performance Prediction Procedure considers these factors by lowering the predicted $DeNO_x$ results depending on the severity of both temperature and flow nonuniformities. However, the effectiveness of the process can also be significantly affected by other factors. These factors are:

- Selection of injection location
- Temperature profile fluctuations through boiler
- NH_3 emissions and byproducts formation

This section describes how each of these factors can further limit the Exxon efficiency predictions for coal-fired boilers.

3.2.1 Selection of Injection Location

Exxon selected the injection locations for the eight coal-fired utility boilers based on maximizing the performance of the process. In actual retrofit application of NH_3 injection systems, obstructions due to any hardware in place could force the installation of injection grids in less desirable locations. For example, soot blowers are located in all the cavities of the convective section of coal-fired boilers. Soot blowers clean convective tubes of slagging or fouling, and cannot generally be removed without causing operational problems. Therefore, the boiler cavities where the injection grid is to be located would need to accommodate the soot blowers as well as the injection grid.

A detailed feasibility study of retrofitting the injection grid in any of the eight coal-fired boilers cannot be made in this report, since the grid system is proprietary. Figures 3-1 and 3-2 show some details of the Mitsubishi Heavy Industries (MHI) injection system retrofitted on

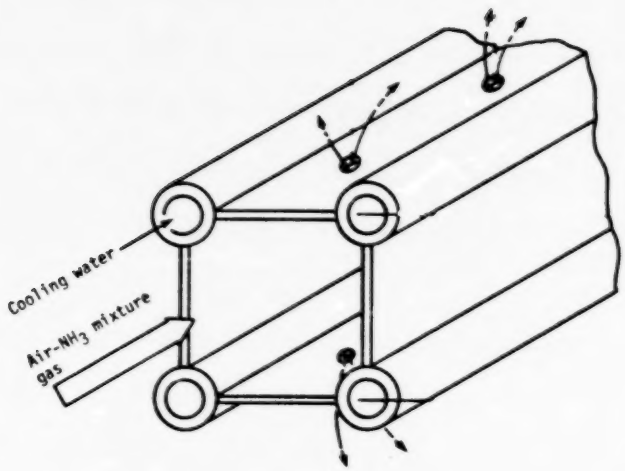

Figure 3-1. Section of the NH_3 injection nozzle pipe for a 375 MW gas-/oil-fired utility boiler in Japan (Reference 3-4).

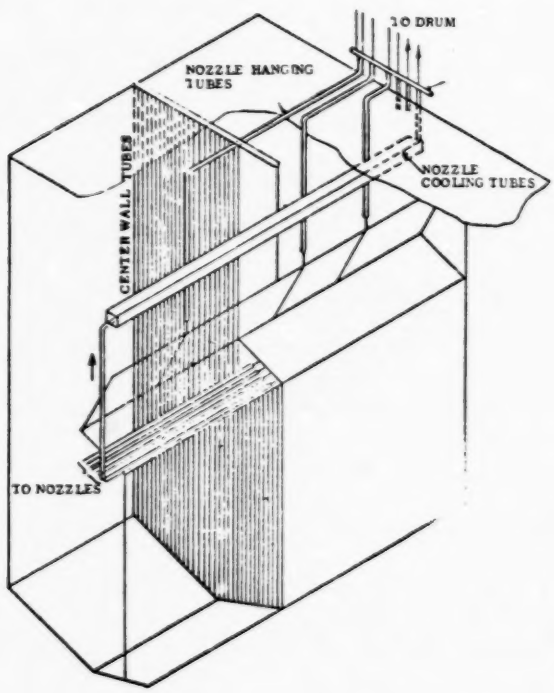

Figure 3-2. Concept of nozzle systems location (Reference 3-4).

the 375 MW gas- and distillate oil-fired boiler in Japan. It should be emphasized that this injector grid design is different from the Exxon's proprietary grid, therefore, it does not represent Exxon's technology. No retrofit problems have been reported with this injection design. However, soot blowers are not usually installed with gas and distillate oil-fired boilers.

The installation of injection grids within tube banks can also result in retrofit problems causing the relocation of the injection grid. For example, in most cases, installation of injection grids within tube banks would necessitate removal of rows of convective tubes. Depending on the design of the grid, one or two rows of tubes might have to be removed. If the removed cooling surface accounts for a significant portion of the total surface of the tube bank, a loss in boiler efficiency or operational problems could result.

Table 3-2 shows the effect of relocating the dual load injection grid from the tube bank to the upstream cavity. These data were obtained using the Exxon-developed Performance Prediction Procedure. For the small 130 MW boiler the effect is minimal. Therefore, the injection grid should be located in the cavity. In the case of the 333 MW horizontally opposed (HO) boiler, the effect is highly significant for the 75 percent boiler load operation. For this boiler, a three grid injection system might be considered if the intube injection location proves unfeasible. For the cyclone boiler (CY), the effect is not very dramatic; NH_3 injection in the cavity might be more suitable.

It should be pointed out, however, that bending a convective tube could also accommodate the installation of the grid at the required location. Questions regarding the actual retrofit of the NH_3 injection

TABLE 3-2. ESTIMATED EFFECT OF INJECTION GRID RELOCATION ON PREDICTED $DeNO_x$ RATES -- $NH_3/NO = 1.5$

Boiler ID	Load (percent MCR)	Predicted $DeNO_x$ Rate With NH_3 Injection Within Tube Bank	Estimated $DeNO_x$ Rate With NH_3 Injection Upstream of Tube Bank
B&W 130 MW FW	100	48	48
	75	48	49
B&W 333 MW HO	75	56	37
	50	56	64
B&W 400 MW Cy	100	57	52
	75	57	60

system cannot be addressed properly because of the lack of data on the Exxon proprietary grid design. However, it is important that these possible limitations be considered in assessing the feasibility of the Thermal $DeNO_x$ Process.

Another factor to be considered when installing the injection grid is the position of the grid relative to the nearest upstream soot blower. Soot blowers may be needed to maintain the surface of the injection grid clean and prevent flyash accumulation and slow plugging of any of the nozzles especially during a loss of air flow through the nozzles. In addition, a backup NH_3 delivery system might be necessary to prevent sudden shutdown of the flow at the nozzles and also prevent the accumulation of flyash deposits on the nozzle exit.

In general, some compromise might have to be adopted when the actual location of an injection grid is determined. This compromise is forced by the problems in keeping nozzle and grid surfaces clean of deposits which might interfere with NH_3 injection, and problems with tube bank modifications causing loss of efficiency or boiler operational problems. Therefore the optimum location of NH_3 injection might not be feasible in all cases, and a reduction in $DeNO_x$ rate might result when an alternate location is used.

3.2.2 Flue Gas Temperature Fluctuations

The performance of the Thermal $DeNO_x$ Process is extremely sensitive to flue gas temperatures. In fact, pilot-scale testing under well controlled conditions showed that the $DeNO_x$ rates are rapidly reduced if the flue gas temperature at the injection location varies by more than 110^oC (200^oF) from the desired level of about 960^oC. Flue gas temperature fluctuations of this magnitude often occur in the convective sections of coal-fired boilers even during constant heat input operation. These temperature changes will cause some decrease in the performance of the process in addition to all decreases accounted for by Exxon. Although it is difficult to predict the magnitude of the loss in $DeNO_x$ performance, a prospective user should be aware of the existence of those potential problems.

The boiler design and operating characteristics which cause fluctuations in the temperature of the flue gas exiting the furnace and the convective passes are:

- Furnace slagging
- Tube fouling
- Soot blowing

- Load variation
- Operational upsets
- Heterogeneous coal properties

Figure 3-3 shows the areas where slagging and fouling occur in a coal-fired utility boiler. The flue gas temperature at the NH_3 injection location is affected by both slagging and fouling. Generally, slagging of the furnace walls will cause a larger temperature effect for the upstream grid location (low boiler loads) than for the downstream one (high boiler loads). When slagging is compounded with fouling the opposite is true. The following comments refer to each of these flyash deposition effects in coal-fired utility boilers.

3.2.2.1 Slagging

Nearly all coals will slag the furnace walls at some rate. However, subbituminous coals usually cause higher slagging rates than bituminous coals. As flyash is deposited on furnace walls, the heat transfer to the water wall decreases, increasing the temperature of the flue gas exiting the furnace. Thus, temperature is usually carefully monitored by the boiler operator and the appropriate steps are taken to maintain the temperature within a safe limit. This limit is dictated by high superheater steam temperature combined with high attemperator water flow rates. Safe temperature limits can be maintained by activation of furnace soot blowers or lowering the burner tilt (for tangential and turbo furnace boilers only), or both. However, before these steps are taken, temperature at the furnace exit can easily increase by $100^{o}C$ ($180^{o}F$).

This temperature increase will then cause corresponding increases in the Temperature At Point of Injection (TAPI) at the NH_3 injection locations. Although the Exxon's Performance Prediction Procedure

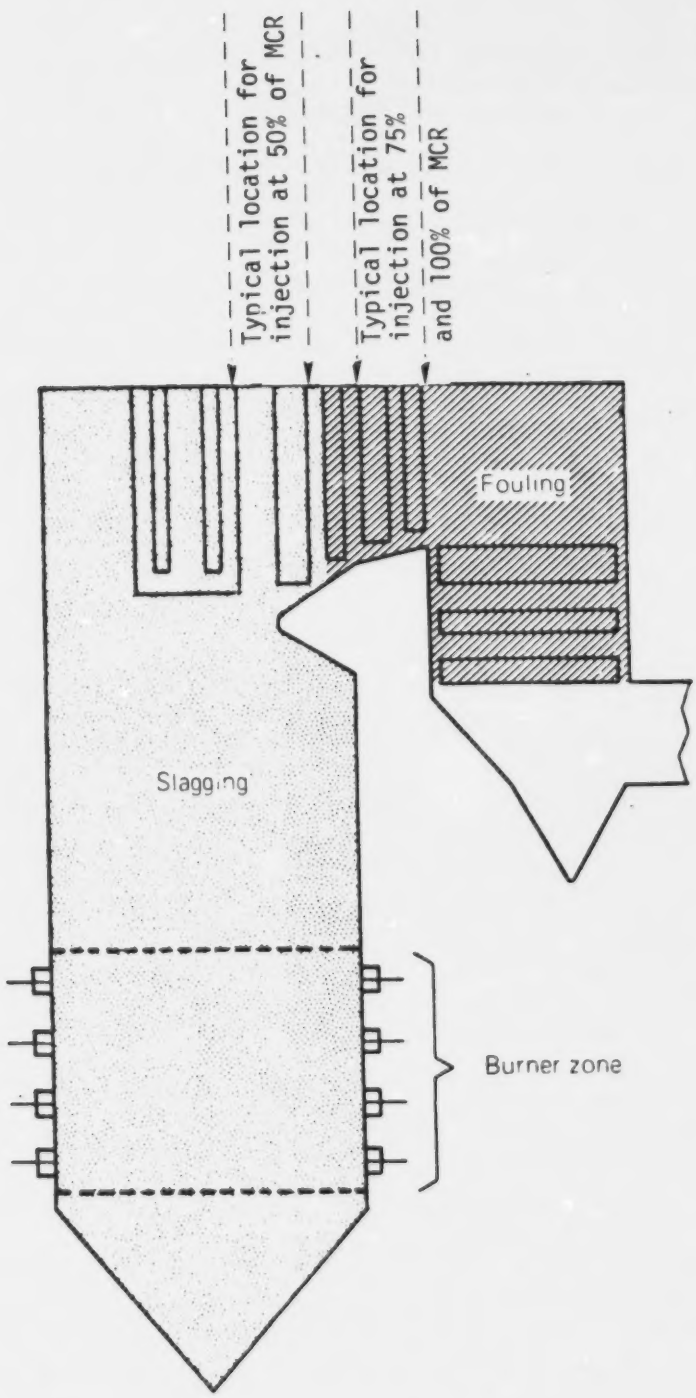
Typical location for injection at 50% of MCR
Typical location for injection at 75% and 100% of MCR
Fouling
Slagging
Burner zone

Figure 3-3. Deposition zones in a coal-fired boiler.

indicates that an increase in temperature will also affect the effective residence time of the gases, for the low load cases, the loss in $DeNO_x$ performance might be as high as 20 percent.

The rate of furnace slagging is difficult to predict. Coal properties such as the ash fusion temperature and viscosity vary significantly among coal mines and often within one single mine. Therefore in the case of a coal-fired boiler retrofitted with the Thermal $DeNO_x$ system, a careful characterization of flue gas temperature variations with furnace slagging is necessary before selecting the injection location. However, fluctuations in flue gas temperatures due to slagging rates and soot blowing cycles may lower $DeNO_x$ performance below the Exxon predictions.

3.2.2.2 Fouling

Another important characteristic of large coal-fired boilers is the fouling of the convective tubes. As in the case with slagging, fouling is most severe with Western subbituminous coals possessing special ash characteristics such as high sodium content. Figure 3-3 indicates that Exxon located the downstream injection grid in the fouling zone for all eight boilers investigated. The rate of fouling of convective tubes and the effect on flue gas temperatures are difficult to predict. However, the increase in TAPI of the downstream NH_3 injection location can be significant within a soot blowing cycle.

Soot blowing in this case is usually initiated when the temperature of the flue gas entering the air preheater reaches levels unsafe for the air preheater. Temperature may increase by 100^oC (180^oF) at the air preheater inlet before soot blowing is initiated.

Combined slagging and fouling will affect the downstream NH_3 injection grid. Therefore the injection temperature at this location can fluctuate by 100°C within a soot blowing cycle.

Occasionally, an increased TAPI can be beneficial rather than detrimental to the performance of the Thermal $DeNO_x$ Process. In fact, increasing flue gas temperature at the NH_3 injection location actually simulates injecting NH_3 at an upstream location where the flue gas temperatures are higher. For example, the B&W 333 MW boiler operating at 50 percent load has an injection location temperature of approximately 930°C (see Figure 3-4). An increase in TAPI of 50°C caused by ash deposition would simulate injecting NH_3 in the cavity segment No. 3, where flue gas temperature is 980°C. Exxon's Performance Prediction Procedure indicates that the NO_x reduction rate would increase from 56 to 64 percent as indicated in Table 3-2. However, if the boiler were operating at 75 percent load, the $DeNO_x$ rate would decrease from 56 to approximately 40 percent.

In all cases, if the injection location is selected based on a clean furnace and convective tubes, then lower $DeNO_x$ rates can be expected than the ones predicted by Exxon, if averaged over any 1-day period. One compensation of increased flue gas temperature with fouling or slagging is the reduced NH_3 breakthrough emissions. NH_3 emissions should decrease based on the tendency of the reagent to form rather than destroy NO at elevated temperatures.

3.2.2.3 Soot Blowing

Soot blowers operate intermittently in the furnace and convective passes of boilers to remove ash deposits on cooling tubes. Thus, soot blowers participate in the flue gas temperature fluctuation cycle.

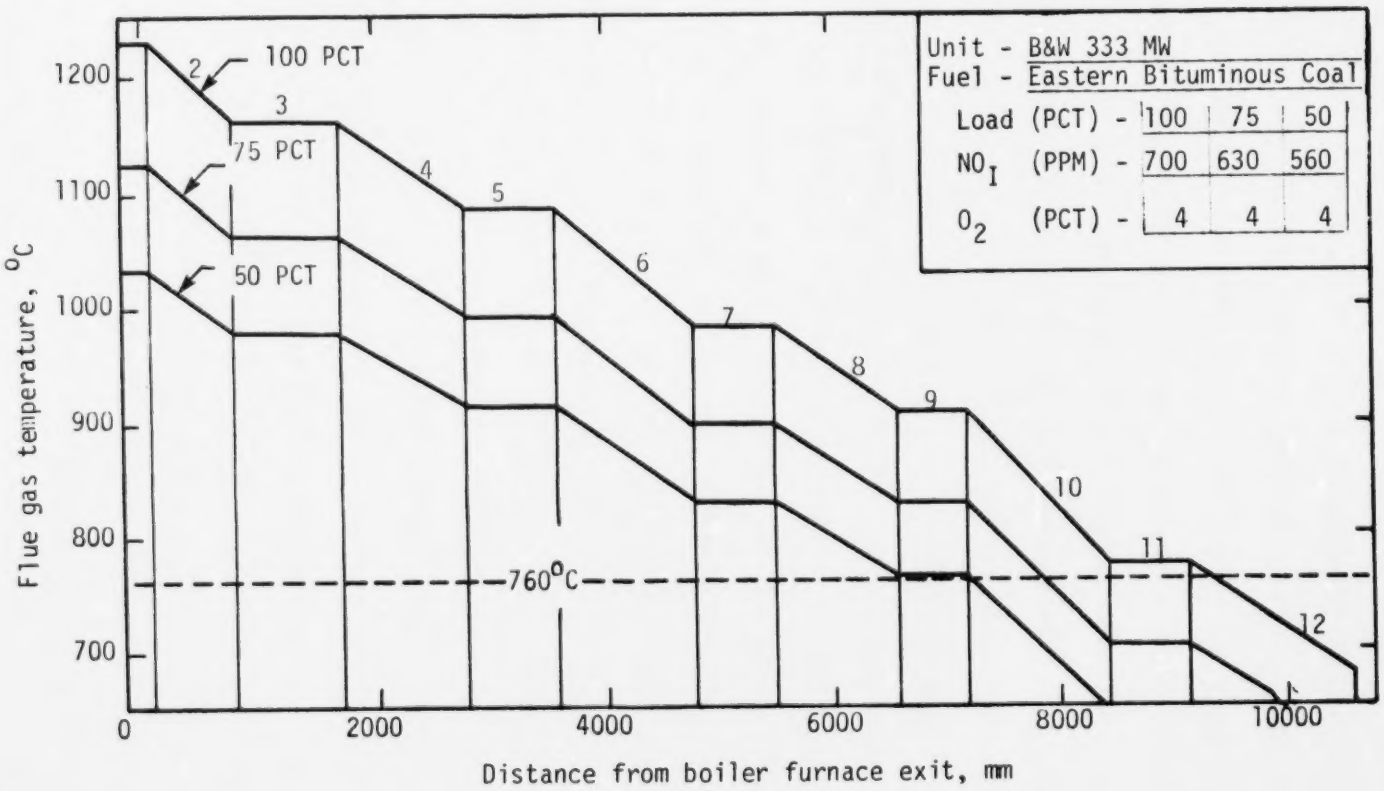

Figure 3-4. Flue gas temperature profile (Reference 3-5).

Slagging and fouling affect temperature uniformly throughout the cross section of a boiler, while soot blowers have a more localized effect due to their sequential operating order. Thus, one zone of a boiler cross section might be cleaned of the deposit while the rest would still be in a dirty state. Nonuniform deposits on furnace and convective tubes could account for large temperature gradients. Gradients of this magnitude may have been included in Exxon's estimated temperature distributions. However, soot blowing may affect boiler operating characteristics, temperature, and NO_x reductions.

3.2.2.4 Load Variations

Heat input to the boiler will naturally change the flue gas temperature profile throughout the boiler. Exxon has chosen a two grid injection system for the Thermal $DeNO_x$ Process to maximize $DeNO_x$ performance at three boiler loads. However, there is no grid operating procedure presented by Exxon when the boiler is operating at loads other than those considered. This is an important consideration because at intermediate loads, NH_3 injection by the improper grid could cause excessive NH_3 breakthrough emissions.

Intermediate load operation may dictate some special grid operating arrangement to maximize NO reduction and minimize NH_3 emissions. Mitsubishi Heavy Industries (MHI) documented their application of the Thermal $DeNO_x$ Process on the 375 MW gas- and oil-fired boiler (Reference 3-4). MHI's suggested Thermal $DeNO_x$ procedure for their special injection system during the entire boiler operating load range is shown in Figure 3-5. It is important to note that one of two main criteria for the NH_3 injection rate and the selection of the operating grid is the NH_3 breakthrough emissions. In this particular case, the

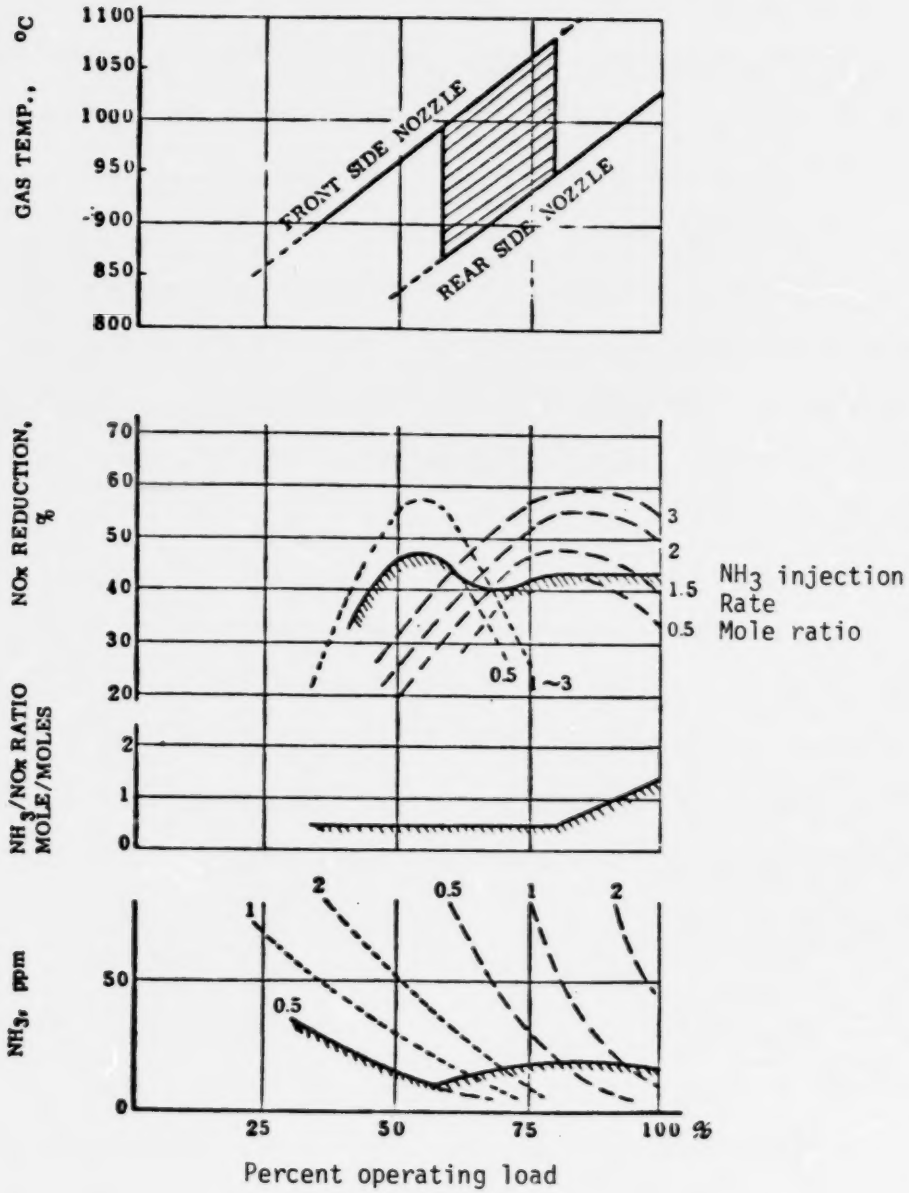

Figure 3-5. NO_x reduction performance on 375 MW boiler at various load operation (Reference 3-4).

front side injection grid is operated at $NH_3/NO = 0.5$ up to a load of 60 percent. Between 60 and 75 percent, both grids are operated with a combined NH_3 injection rate of $NH_3/NO = 0.5$. Above 75 percent only the rear grid is used with correspondingly increasing NH_3 injection rates. Following this procedure, NH_3 emissions are monitored to less than 25 ppm at all boiler loads, according to MHI.

If a similar procedure based on minimal NH_3 emissions were adopted for the eight coal-fired boilers, the $DeNO_x$ efficiencies listed in Table 3-1 might again reflect optimistic levels of system performance. Potential adverse effects of NH_3 emissions are discussed in more detail in Section 3.2.3.

3.2.2.5 Operational Upsets

Operational upsets that might affect the temperature of the flue gas can be mainly related to burner operation. For example, during a pulverizer outage, the coal flow to selected burners will be terminated. These burners, often located randomly on the furnace walls of front and horizontally fired boilers, are on a same level in the case of tangentially fired boilers. For wall fired boilers, the random location of burners out of service could cause high temperature gradients. For tangential boilers, the temperature gradient should not be affected because of the symmetry of the shut-off burners with furnace geometry.

The increased flue gas temperature gradients reduce the $DeNO_x$ performance and increase NH_3 breakthrough, if NH_3 injection rate is not corrected during the boiler upset. Because these outages can be prolonged, NH_3 emissions could create a temporary environmental concern.

Temperature gradients due to pulverizer outages on wall fired boilers are difficult to estimate, because of the associated effect of

load reduction. Operational upsets are not a part of the $DeNO_x$ Performance Prediction Procedure and cannot be really considered in any prediction scheme. However, operational upsets could be a serious consideration if NH_3 breakthrough is intolerable.

3.2.2.6 Heterogeneous Coal Properties

During pilot-scale testing by KVB, the optimum reaction temperature was found to be approximately the same for firing natural gas as for three coals. A fourth coal apparently showed an optimum temperature that was approximately 55°C higher. Experiments are now underway at Exxon to determine whether this is a real effect or an experimental artifact. If this possible effect of coal type is real, it will have to be considered in implementing ammonia injection on coal-fired boilers.

3.2.3 NH_3 Breakthrough and Equipment Maintenance

The most important precautions in preventing NH_3 breakthrough are careful design, location, and operation of the injection grid. Higher than optimum $DeNO_x$ temperatures are effective in maintaining low NH_3 emissions but with a slight penalty in NO_x reduction efficiency. Despite these precautions, NH_3 emissions varying from 10 to 40 ppm were measured from the full-scale commercial application of the Thermal $DeNO_x$ Process on gas- and oil-fired units. By comparison, the flue gas NH_3 concentration used in Industrial Environmental Research Laboratory (IERL) environmental assessments to signify a potential environmental health hazard is 24 ppm (Reference 3-6). This concentration is intentionally conservative for use in screening effluent measurements to identify those requiring further study. Nontheless, the NH_3 breakthrough observed in Thermal $DeNO_x$ field demonstrations is of comparable magnitude and bears further study.

With fuels containing sulfur, the ammonia which did not react with NO_x easily reacted with SO_3 and H_2O to form ammonium sulfates. These sulfates condense and become adhesive solids/liquids at temperatures typical of the air preheater section of large steam generators. Sulfate deposits, although not occurring in all Exxon full-scale applications, have caused some draft loss problems with two oil-fired boilers. These boilers are a 375 MW utility steam generator firing a 0.2 percent S oil and an industrial size steam generator firing oil with an unspecified sulfur content. On-steam water washing was successfully used to remove sulfate deposits from the air heater in the industrial boiler.

The possibility of NH_3 breakthrough and associated implications caused by its presence in SO_x-laden gases, deserves further assessment in establishing the feasibility of the Thermal $DeNO_x$ Process for coal-fired boilers. This section presents possible limitations based on estimated NH_3 breakthrough emissions from coal-fired boilers.

3.2.3.1 Estimated NH_3 Emissions

NH_3 emissions leaving the reaction zone of the $DeNO_x$ Process are difficult to estimate, because of their extreme dependence on a combination of factors. Some of these factors include:

- Injection grid design
- Reagent mixing
- Injection temperature
- NH_3/NO injection rate
- Use of a temperature controlling additive.

The first three factors depend on boiler geometry and operating conditions and each is extremely variant between boilers. The NH_3 injection rate depends on the degree of reduction that is desired.

Unfortunately NH_3 breakthrough can occur with the higher NH_3 injection rates required for high DeNOx efficiency. Additives can help reduce NH_3 emissions. However, additives add significantly to the cost of the process and their use creates concerns over safety.

In general, NH_3 emissions are expected with any full-scale application of the Thermal $DeNO_x$ Process. These emissions could vary from a few ppm to more than 50 ppm especially for the case of maximum required NO_x reduction efficiency. KVB tests showed that even under the controlled operation of pilot-scale testing, NH_3 breakthrough in the flue gas from coal combustion could measure approximately $NH_{3\text{-out}}/NH_{3\text{-in}}$ = 0.1 to 0.2 for an injection rate of NH_3/NO = 1.5. (Refer to Figure 2-9 and Reference 3-7). The effective residence time in the KVB pilot-scale coal-fired furnace was on the order of 0.85 seconds due to the cooling of the gases by 165°C (329°F) over a distance of 0.6 meter (2 feet) in the reaction zone. The injection system for the KVB experiments had 5 nozzles covering an approximate cross sectional area of 0.55 square meters (6 ft^2).

Table 3-3 presents estimated NH_3 emissions for the eight coal-fired utility boilers. Ammonia emissions of $NH_{3\text{-out}}/NH_{3\text{-in}}$ = 0.043 and $NH_{3\text{-out}}/NH_{3\text{-in}}$ = 0.129 were selected to estimate the concentration of NH_3 breakthrough for the ammonia injection rates of NH_3/NO = 1.0 and NH_3/NO = 1.5 respectively. These $NH_{3\text{-out}}/NH_{3\text{-in}}$ values correspond to average NH_3 emission rates obtained during KVB pilot-scale tests with coal combustion. The use of NH_3/NO = 0.5 was not considered because experiments showed negligible NH_3 breakthrough emissions with this ammonia injection rate.

TABLE 3-3. ESTIMATED NH_3 EMISSIONS (100 PERCENT BOILER LOAD AND WITHOUT COMBUSTION MODIFICATIONS)

Unit	NO Emission (ppm)	NH_3/NO = 1.0			NH_3/NO = 1.5		
		NO_x Reduction (Percent)	NH_3 (ppm)	NH_3-Out (ppm)	NO_x Reduction (Percent)	NH_3 (ppm)	NH_3-Out (ppm)
B&W 130 MW	500	38	500	21	48	750	64
B&W 333 MW	700	48	700	30	63	1050	90
B&W 400 MW	1000	45	1000	43	57	1500	129
CE 350 MW	500	52	1500	21	58	750	64
CE 800 MW	530	52	530	23	57	795	68
FW 330 MW	850	41	850	36	54	1275	109
FW 670 MW	700	47	700	30	60	1050	90
RS 350 MW	700	47	700	30	58	1050	90

Table 3-3 indicates that except for three cases, NH_3 breakthrough levels can easily exceed 24 ppm (the acceptable threshold limit used in environmental assessments) (Reference 3-6). NH_3 breakthrough emissions are highest for the cyclone unit because of the initial high concentration of injected NH_3.

To reduce the amount of breakthrough, the ammonia must be injected where the flue gas is hotter, or, injected at a reduced rate. Both methods seem to be equally effective; however, they both decrease the efficiency of the Thermal DeNO$_x$ Process. Reducing the NH_3 injection rate is much less expensive than relocating the injection grid.

In reality, NH_3 emissions cannot be easily predicted because they are affected not only by the NH_3 injection rate and the residence time of the gases but also by other factors such as reagent mixing and reaction temperature fluctuations. These NH_3 emission estimates are considered very preliminary, however, they are indicative of potential NH_3 breakthrough levels. The following pages will discuss potential operational and environmental problems of ammonia breakthrough.

3.2.3.2 Major Implications

Sulfur trioxide (SO_3) is formed by the oxidation of SO_2 in the convective section. The quantity of SO_3 formed is dependent on coal type and excess combustion air levels. Flue gases from bituminous and subbituminous coals may contain SO_3 anywhere from 1 to 5 percent of the total SO_x (SO_2 + SO_3). Lignite, however, may form a significant amount of SO_3 which quickly reacts with alkaline metals to form sulfates.

The presence of NH_3, SO_3 and moisture in the flue gas of coal-fired power plants forms ammonium sulfate or ammonium bisulfate, as shown by the following equations

$$2\ NH_3 + SO_3 + H_2O \longrightarrow (NH_4)_2\ SO_4 \text{ (sulfate)}$$

$$NH_3 + SO_3 + H_2O \longrightarrow NH_4\ HSO_4 \text{ (bisulfate).}$$

NH_4HSO_4 is a liquid above 150°C (300°F). While $(NH_4)_2SO_4$ is a solid up to 235°C (455°F). Liquid and solid ammonium sulfates formed in the ducting of coal-fired boilers could represent a significant operational problem because of fouling and potential corrosion.

Full-scale application of the Thermal $DeNO_x$ Process on oil-fired heaters and steam generators has shown, in most cases, that if NH_3 emissions are maintained below about 45 ppm, and the oil sulfur content is low, air heater corrosion is insignificant. However, on two sources discussed in Section 2, the formation of ammonium sulfates caused increased fouling of air preheater parts and required unit shutdown for maintenance. Exxon recommends on-stream washing of the air preheater when the boiler is retrofitted with Thermal $DeNO_x$.

The amount of sulfate or bisulfate formation is difficult to predict because it depends on the relative concentrations of SO_3 and NH_3 in the flue gas. Table 3-4 shows estimated bisulfate formation for the eight coal-fired boilers in consideration. Coal sulfur contents were set at 1.0, 2.0 and 0.4 for subbituminous, bituminous and lignitic coals, respectively. The amount of SO_3 in the flue gas was estimated at 2 percent of total SO_x for bituminous and subbituminous coals and 0.5 percent for lignite based on a sulfur emissions study (Reference 3-8). Ammonium bisulfate formation was then predicted for varying amounts of SO_3 using the data contained in Figure 3-6.

TABLE 3-4. ESTIMATED FORMATION OF AMMONIUM BISULFATE IN COAL-FIRED UTILITY BOILERS INVESTIGATED -- $NH_3/NO = 1.0$

Unit	Fuel	% S in Fuel	NH_3-Out ng/J	SO_3-Out[a] ng/J	NH_4HSO_4 ng/J (Percent of NH_3 Used)			
					5% SO_3 Reaction		100% SO_3 Reaction	
B&W 130 MW	Subbituminous	1.0	5.2	15	1	(3)	21	(61)
B&W 330 MW	Bituminous	2.0	7.5	27	2	(4)	39	(77)
B&W 400 MW	Lignite	0.4	13	2	0.1	(0.2)	2	(3)
CE 350 MW	Bituminous	2.0	5	29	2	(6)	34[b]	(100)
CE 800 MW	Subbituminous	1.0	6	14	1	(6)	20	(50)
FW 330 MW	Bituminous	2.0	9	29	2	(3)	42	(68)
FW 670 MW	Subbituminous	1.0	7	14	1	(2)	20	(43)
RS 350 MW	Bituminous	2.0	7	29	2	(4)	42	(88)

[a]Assumes SO_3 = 2 percent of SO_x for bituminous and subbituminous coals and 0.5 percent for lignite coals.
[b]Only 80 percent of SO_3 is consumed by NH_3.

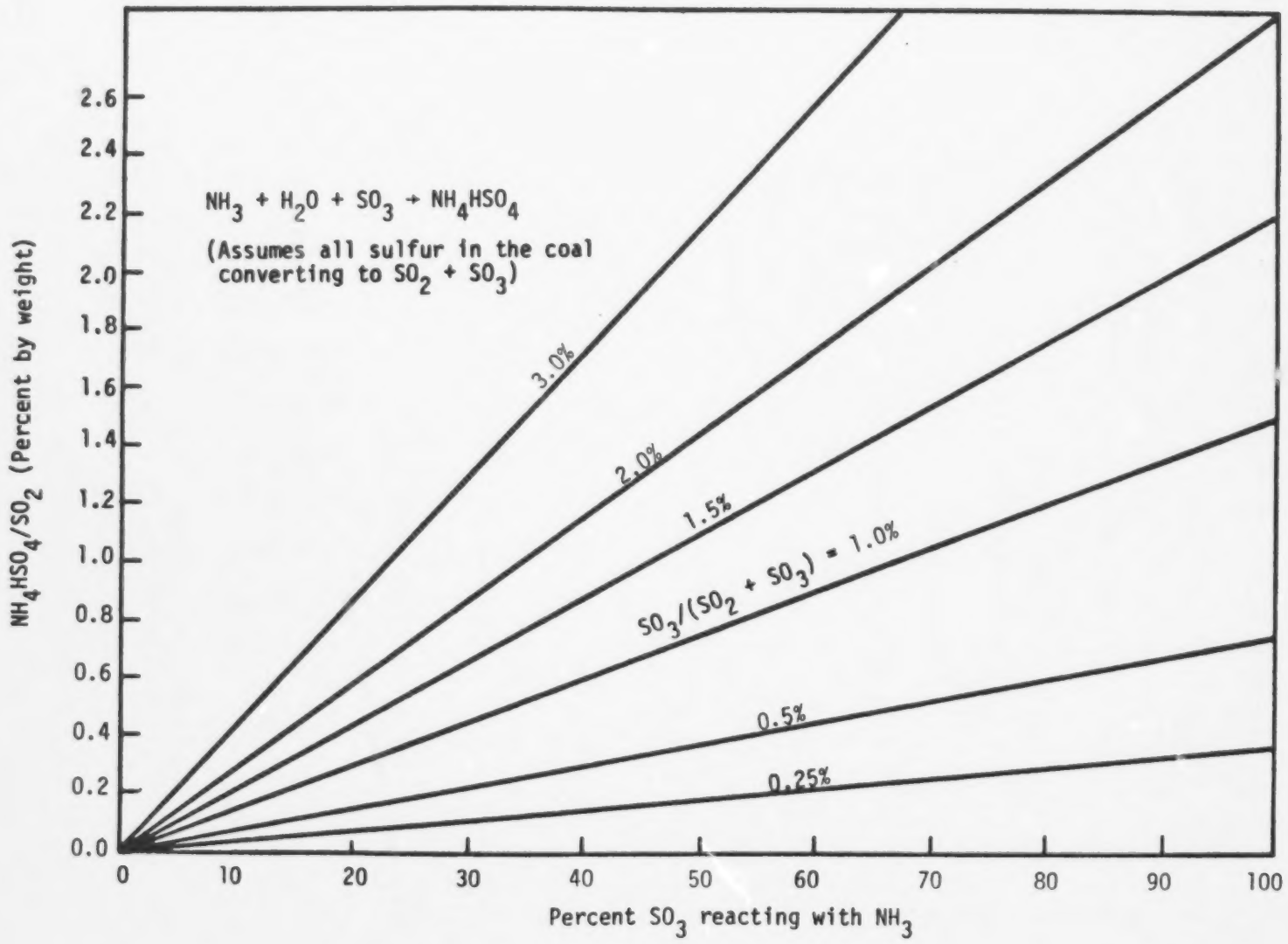

Figure 3-6. Ammonium bisulfate formation as a function of sulfur content in the coal.

Estimated NH_4HSO_4 formation varies from 0.12 ng/J (0.0003 lb/10^6 Btu) for the lignitic coal to nearly 43 ng/J (0.1 lb/10^6 Btu) of heat input for the bituminous and subbituminous coals.

KVB reported a decrease in SO_3 emissions during their pilot-scale testing with coal combustion (Reference 3-7). This decrease, attributed to NH_4HSO_4 formation, ranged from 15 to approximately 50 percent of the initial SO_3 emission levels measured without NH_3 injection. However, the decrease was not proportional to the amount of NH_3 injected in the flue gas. Based on these data it is doubtful that all of the SO_3 from coal-fired boilers will react with NH_3. However, in another study, Dismukes (Reference 3-9) has reported SO_3 reductions ranging from 50 to 90 percent when NH_3 was injected downstream of the air preheater.

Considering the two extreme cases of 5 and 100 percent conversion of SO_3 to ammonium bisulfate, the total emission rates for the eight coal-fired utility boilers operating at full load were calculated. These NH_4HSO_4 emission rates are shown in Table 3-5. Based on the above assumptions, the large, twin-furnace 800 MW Combustion Engineering boiler will form the largest quantities of NH_4HSO_4 due to its size. The smallest rate of formation will be for the lignite-fired cyclone boiler due to the assumed low sulfur content of this coal, and the low percentage of SO_3 available to react with NH_3.

Even though these estimates are crude, it is evident that substantial NH_4HSO_4 could be formed and deposited on the regenerative air preheaters of coal-fired boilers. These deposits can pose severe problems to the operation of the units because of plugging and corrosion.

Studies on a Japanese boiler showed deposits of ammonium sulfates built up to a thickness of 7 to 10 mm (0.28 to 0.39 inches) in the tubular

TABLE 3-5. PREDICTED AMMONIUM BISULFATE EMISSION RATES

Unit	Heat Rate Btu/kW-hr	NH_4HSO_4 kg/hr (Mg/year)[a]			
		5% SO_3 Reaction		100% SO_3 Reaction	
B&W 130 MW	9,500	1.36	(9.52)	26.9	(188.3)
B&W 330 MW	10,000	7.18	(50.26)	143.9	(1007.3)
B&W 400 MW	10,000	0.55	(3.85)	10.4	(72.8)
CE 350 MW	10,000	7.64	(53.48)	125.8	(880.6)
CE 800 MW	10,000	9.18	(64.26)	177.6	(1243.2)
FW 330 MW	10,500	7.18	(50.26)	147.4	1031.8)
FW 670 MW	10,500	7.68	(53.76)	149.1	(1043.7)
RS 350 MW	10,000	7.64	(53.48)	155.4	(1087.8)

[a]Mg = 10^6 grams, assumes 80% load factor

air preheater after 1100 hours of uninterrupted operation. The boiler fired a light oil containing very little sulfur. In the application of the MHI noncatalytic ammonia injection process on the 375 MW oil/gas-fired utility boiler at the Chita Station in Japan, fouling forced operation to a halt twice in one year to wash the air preheater. The sulfur content of the oil burned at the Chita station was 0.2 percent. In contrast, the sulfur content of bituminous coal is usually around 2.0 percent. Complicating matters, these deposits are apparently not easily removable with soot blowers and the water washing to remove the sulfate deposits can sometimes necessitate boiler derating or even shutdown.

Coal-fired utility boilers are typically taken "off the line" once a year as part of their scheduled maintenance. During this time the regenerative air preheaters are washed to remove flyash deposits. Large boilers are often equipped with two preheaters. If the fouling of the air preheaters caused by NH_4HSO_4 formation is such that the yearly washing will suffice to remove the deposits, then the operation of the boiler should not be affected. However, with the NH_4HSO_4 formations listed in Table 3-5, the fouling could be severe enough to require additional washings.

Air preheater washing is usually carried out under one of the following conditions: out-of-service, in-service-isolated, or in-service-on-stream (Reference 3-10). Out-of-service washing is accomplished when the boiler is shut down for normal scheduled inspection or for repair work. This type of washing represents the most effective washing operation because it allows for a thorough inspection of the air preheater parts.

In-service-isolated washing is depicted in Figure 3-7. Boilers equipped with two preheaters can continue to operate during washing cycles by switching to one preheater operation as shown in Figure 3-7. However, the switch to single preheater operation would mean a reduction in boiler load for the duration of the washing.

In-service-on-stream washing is carried out while allowing both gas and air to pass through the air preheater. On-stream washing is applicable only in those installations where the ductwork and location of drains are such as to eliminate or at least minimize the amount of moisture entering the dust collectors, precipitators, windboxes, and boilers. On-stream washing is required before ash buildup reaches the point when any actual plugging occurs. Therefore, it usually commences when the gas side pressure differential increases to a maximum of 0.5 inch (W.G.) over design specifications.

Unscheduled cleaning of the air heater due to NH_4HSO_4 deposits could in some cases require boiler derating or even shutdown, resulting in revenue loss for the utility and increased cost of maintenance.

In conclusion, it is reemphasized that the above discussion is only qualitative and based on numerous assumptions. The implications of NH_3 emissions in SO_3-laden flue gas streams should, however, be carefully considered. Reported measurements of NH_4HSO_4 deposits in air preheaters have shown that fouling can occur with low sulfur oils. This problem can intensify with combustion of high sulfur coal. Low NH_3 emissions may lower the formation of NH_4HSO_4. In most cases, however, the formation is limited more by the SO_3 content of the flue gas than the NH_3 concentration. Thus, low NH_3 breakthrough, 50 ppm or less, can still cause increased air preheater fouling and corrosion.

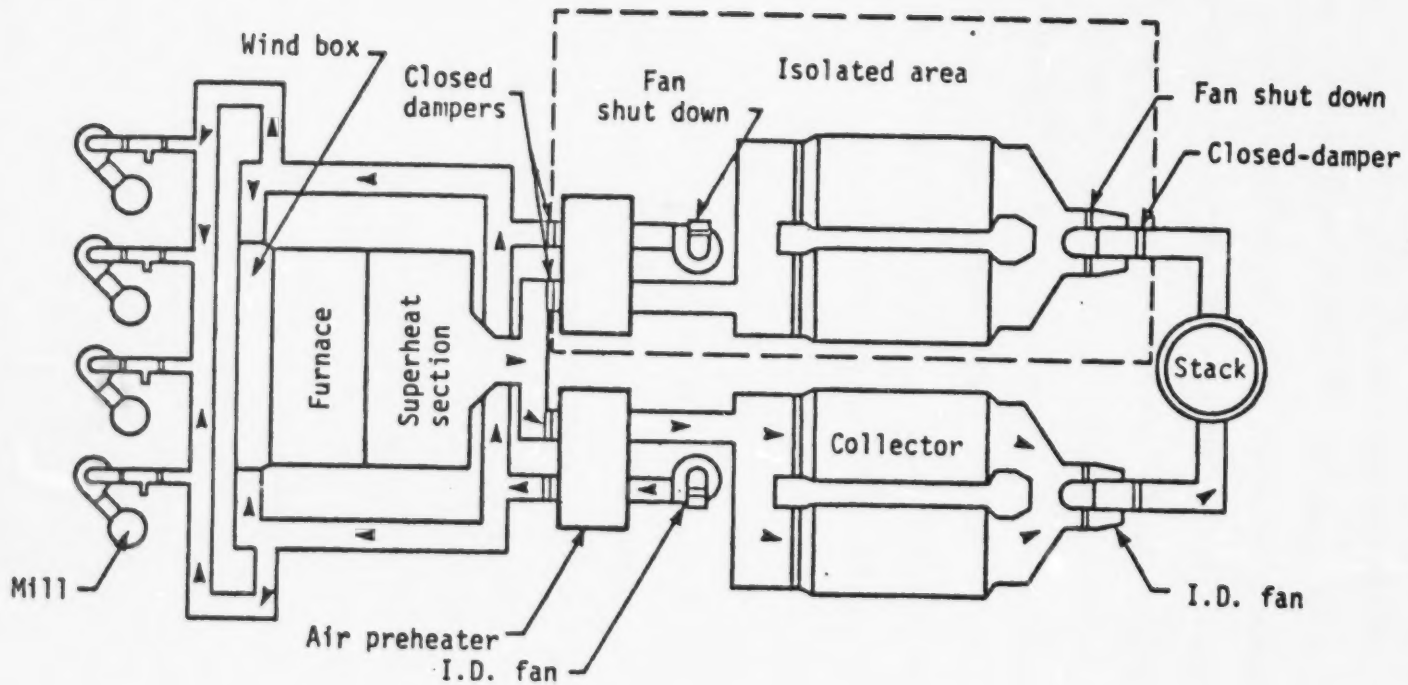

Figure 3-7. On-stream washing of air preheater on a boiler with dual air preheater arrangement (Reference 3-10).

3.2.3.3 Environmental Considerations

Exxon and KVB have reported that emissions of carbon monoxide, nitrates and sulfur oxides do not increase as a result of NH_3 in the flue gas. However, the effect of NH_3 on particulate emissions in the flue gas of coal-fired boilers has probably not been addressed in sufficient detail. The following discussion present some of the reported findings of NH_3 injection effects on particulate emissions.

The presence of NH_3 in the flue gas definitely affects the performance of electrostatic precipitators (ESP's). Both adverse and beneficial effects on the performance of the collector can occur depending on coal characteristics, ESP design, and flue gas conditions. For example, the depletion of SO_3 in the flue gas by NH_3 can adversely affect the ESP efficiency. The presence of SO_3 reduces excessively high particle electrical resistivity, an unfavorable property of dust entering the collector. Figure 3-8 shows how SO_3 flue gas concentration affects collection efficiency. Furthermore, $(NH_3)_2SO_4$ formed by reaction of SO_3, NH_3 and water vapor can also reduce electrostatic precipitation collection efficiency (Reference 3-12).

NH_3 has also been used as a flue gas additive when injected downstream of the air preheater. Some initial work by Reese and Greco (Reference 3-13) demonstrated that when flue gas temperatures entering the electrostatic precipitator are below the acid dew point (which means the presence of condensed H_2SO_4), NH_3 injection improves ESP efficiency by neutralizing H_2SO_4. NH_3 neutralizes H_2SO_4 by forming ammonium sulfate. Figure 3-9 shows the negative effect of condensed H_2SO_4 and Figure 3-10 shows how NH_3 injection increases ESP performance.

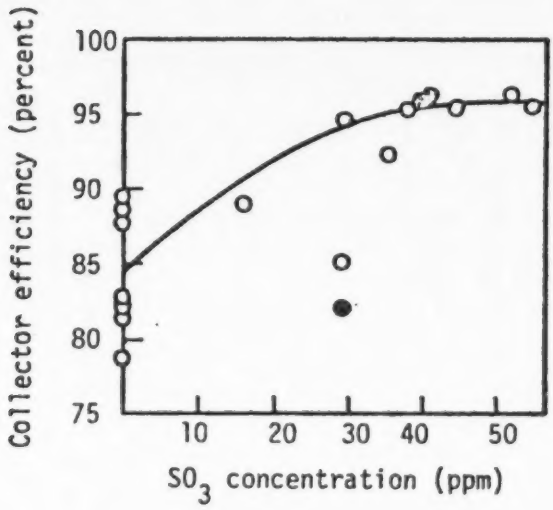

Figure 3-8. Effect of SO_3 conditioning on collection efficiency of a coal-fired utility boiler (Reference 3-11).

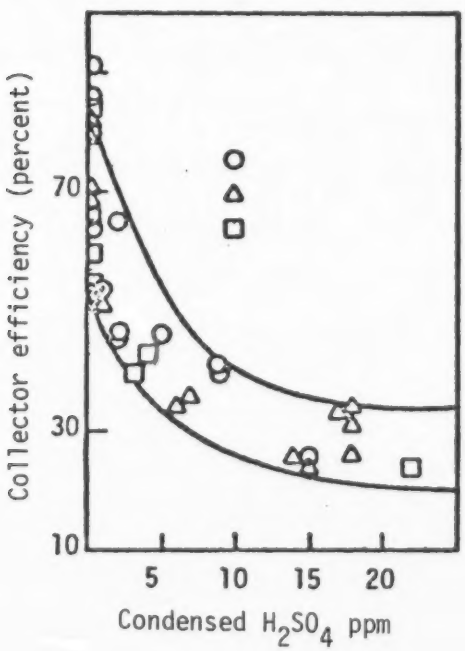

Figure 3-9. Collector performance as a function of the amount of condensed sulfuric acid in flue gas (Reference 3-13).

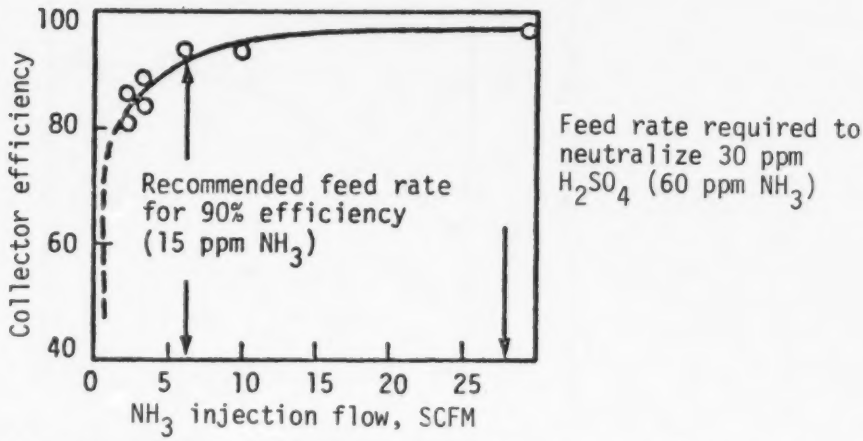

Figure 3-10. Collector efficiency as a function of ammonia feedrate (Reference 3-13).

NH_3 can also improve ESP efficiency by increasing the cohesiveness of the ash. Dismukes (Reference 3-14) discovered that ammonia conditioning was effective in overcoming the loss of collected flyash by rapping reentrainment, a problem which occurs with very low resistivity ash (high-sulfur coal).

Dismukes also cited some deleterious effects of ammonia in the flue gas entering the ESP. The first of these effects is the "space-charging" effect or enhancement of sparking between well-aligned electrodes. This effect was noted on a few coal-fired boilers when NH_3 was used to condition the flue gas. Dismukes estimates that this problem can be serious when burning low sulfur Western coals. Space-charging would then occur with these coals unless the high flyash resistivity is lowered.

The second of these effects is the increase in fine particulate emissions. Table 3-6 shows data on concentration of particles smaller than 1.0 micron as measured by a diffusion battery. The Widows Creek plant was one of three coal-fired plants whose emissions were measured for

TABLE 3-6. CONCENTRATIONS OF SUBMICRON PARTICLES AT THE WIDOWS CREEK PLANT (Reference 3-14)

Sampling Location[a]	Injected NH_3 Concn, ppm	Minimum size Detected, μm	Particle Concn, no./cm	No. % Above Minimum Size
Inlet	0	0.005	6.5×10^6	100
		0.014	5.4×10^6	85
		0.050	2.9×10^6	45
Inlet	11	0.005	19.5×10^6	100
		0.014	16.7×10^6	85
		0.050	11.2×10^6	57
Inlet	0	0.005	12.0×10^6	100
		0.014	10.3×10^6	89
		0.050	6.3×10^6	52
Inlet	23	0.005	30.9×10^6	100
		0.014	29.0×10^6	94
		0.050	17.0×10^6	55
Outlet	0	0.005	0.43×10^6	100
		0.014	0.35×10^6	81
Outlet	20	0.005	1.40×10^6	100
		0.014	0.98×10^6	70
		0.050	0.79×10^6	56

[a]Gas temperature, 132°C (270°F)

particle size. Similar results appear from other sources. It is evident that concentrations of submicron particles increased as NH_3 was injected prior to the precipitator. In these experiments, the increase in small particle concentration did not vary substantially with increasing ammonia concentration. Dismukes assumed that only the particulate formed between SO_3 and ammonia was detected in addition to the flyash particulate The increase in fine particle emission is also detected at the outlet of the precipitator. It was also pointed out that as submicron particles increased, NH_3 reduced SO_3 in the flue gas. This reduced the concentration of sulfuric acid mist formed by condensation of the plume.

In summary, NH_3 in the flue gas may vary ESP performance in both a beneficial and adverse way. Table 3-7 summarizes the effects described above. The dominant effect is unclear. Further investigation on the effect of NH_3 breakthrough on ESP performance may be warranted.

TABLE 3-7. EFFECTS OF NH_3 EMISSIONS ON ESP PERFORMANCE AND PARTICULATE EMISSIONS

Beneficial		Adverse	
Effect	Mechanism	Effect	Mechanism
Increased ESP efficiency	Neutralization of condensed SO_3 by reaction with NH3	Reduced ESP efficiency	Increased flyash resistivity by depletion of gaseous SO_3 reacting with NH_3 and formation of $(NH_3)_2SO_4$
Increased ESP efficiency	Increased cohesiveness of flyash from high sulfur coal	Reduced ESP efficiency	Space charge effect when burning low sulfur Western coals unless particle resistivity is reduced
Reduced fine particulate emissions	Acid mist elimination by depletion of SO_3 in the flue gas with NH_3	Increased fine particle emissions	Reaction of NH_3 with SO_3 and fine particle formation

REFERENCES FOR SECTION 3

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SECTION 4

COST ANALYSIS

The retrofit costs of NO_x controls for utility boilers depend on numerous site-specific factors such as boiler design configuration, operational and installation problems, and the amount of design engineering required prior to retrofit. For the Thermal $DeNO_x$ Process, cost estimates are further affected by variations in ammonia and carrier gas cost and variations in temperature, flowrate, and NO profiles in the convective section. Finally, control cost projections are dominated by projections of ammonia supply and cost.

Recently, Exxon has reported that the total operating cost of the Thermal $DeNO_x$ Process can vary widely, depending on the level of control, between \$1.75 and \$8.61/kW-yr for retrofit application on utility boilers (Reference 4-1). These costs compare with \$0.26 to \$3.04/kW-yr for combustion modifications (Reference 4-2). Based on these costs, NH_3 injection is, in most cases, more expensive than combustion modifications. Therefore, the process becomes most attractive when used to augment combustion modifications in order to reach stringent emission levels.

Section 4.1 reviews the costs of the Thermal $DeNO_x$ Process reported by Exxon for the eight utility coal-fired boilers. These results are then compared with costs developed by Acurex using a standardized cost analysis procedure. Section 4.2 considers future cost projections and

presents the impact of implementing the Thermal $DeNO_x$ Process on the ammonia market, feedstock supplies, and their costs.

4.1 RECENT REPORTED COST ESTIMATES

The following section discusses Exxon's cost analysis of Thermal $DeNO_x$ for eight coal-fired boilers which represent the range of utility boilers presently manufactured. The following assumptions were made by Exxon in developing these costs (Reference 4-1):

- Fixed costs are Total Erected Costs (TEC), 2nd quarter, 1977, U.S. Gulf coast. TEC was obtained by multiplying the installed cost by a cost factor of 1.43. TEC includes contractor engineering charges and fees, field labor overhead and burden. Burden includes labor benefits such as health insurance, holidays, etc.
- Reagent fixed costs include the NH_3 storage vessel, vaporizer, and piping
- Carrier fixed costs include air compressors and piping
- Onsite fixed costs include two injector grids, instrumentation and controls
- Operating costs are for the 100 percent load condition
- Ammonia operating cost is based on an NH_3 cost of \$187/Mg (\$170/ton)
- Carrier operating cost is \$14.48/10,000 SCM (\$0.41/10 000 SCF) for an air compressor power requirement of 820.6 kW (1100 HP) per 10,000 SCFM and electricity cost of \$0.03/kW-hr.

- Annual amortization of the capital cost is taken as 20 percent of the initial investment which accounts for finance costs depreciation and maintenance.
- The annual service factor is 80 percent

Figure 4-1 shows the cost of $DeNO_x$ ($/MW-hr) for seven boilers as a function of initial NO_x level in ppm for approximately 50 percent reduction. For some units two data points are plotted for the same initial NO_x level because of two different percent NO_x reductions. This figure indicates that $DeNO_x$ cost is essentially independent of boiler type even though flue gas temperature profiles and flow path configurations cause differences in optimum $DeNO_x$ locations among boilers. Additionally, the cost of $DeNO_x$ increases with increasing initial NO_x level for a given percent reduction.

Figure 4-2, which displays the cost of $DeNO_x$ normalized by the ppm reduction as a function of unit size, shows that except for the small size boilers, the cost of $DeNO_x$ decreases with unit size. The data shown in Figure 4-2 include normalized costs for both trim NO_x reduction cases as well as maximum NO_x reduction cases considered by Exxon. The trim cases involve reducing emissions to the proposed NSPS standards of 285 ng/J (450 ppm) for bituminous and lignitic coals and 215 ng/J (375 ppm) for subbituminous coal. The maximum reduction cases, instead, require NO_x reduction to 72 ng/J (300 ppm) and 129 ng/J (225 ppm) respectively.

Figure 4-3 presents the cost of $DeNO_x$ normalized for the ppm reduction as a function of the initial NO_x concentration. Clearly, as the initial NO_x concentration is reduced, the cost per unit NO_x removed is higher. This is primarily because the $DeNO_x$ efficiency

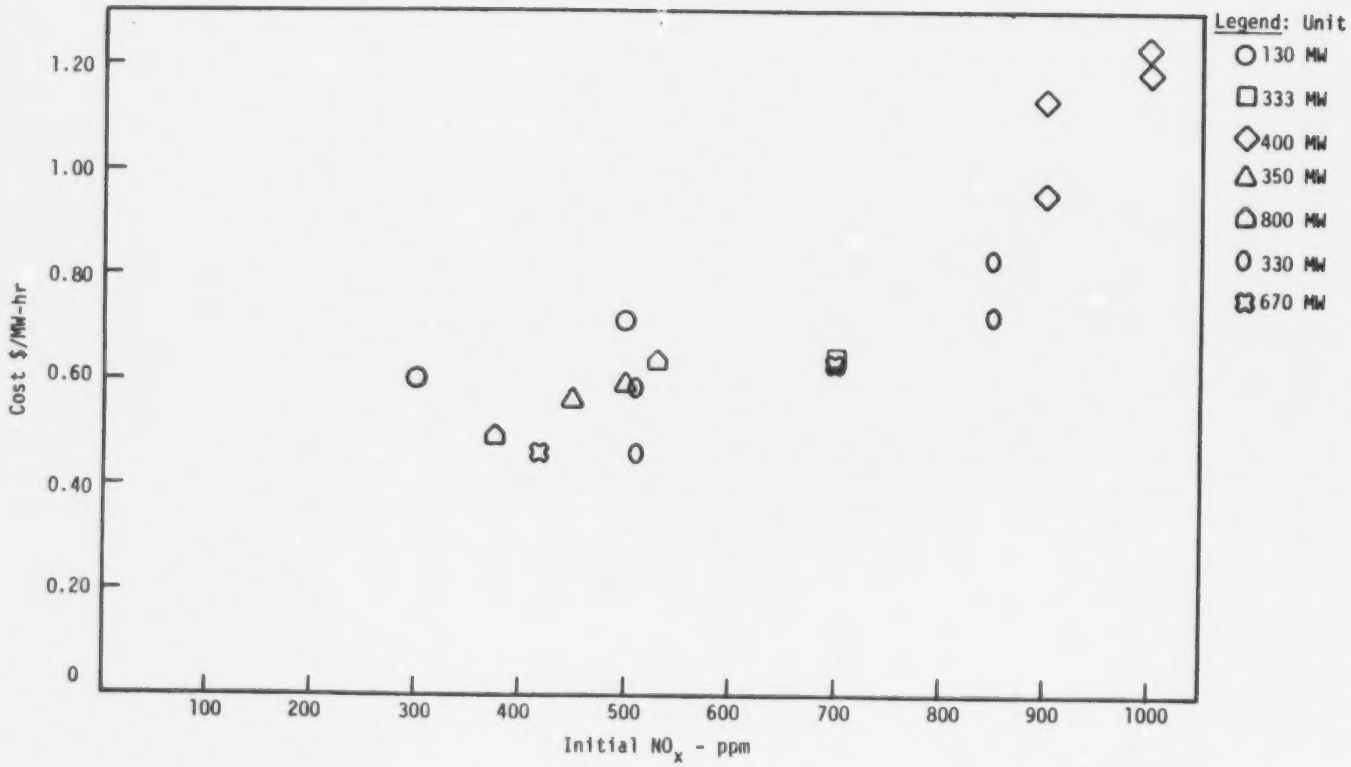

Figure 4-1. Cost of NH_3 injection for approximately 50 percent reduction in NO_x emissions.

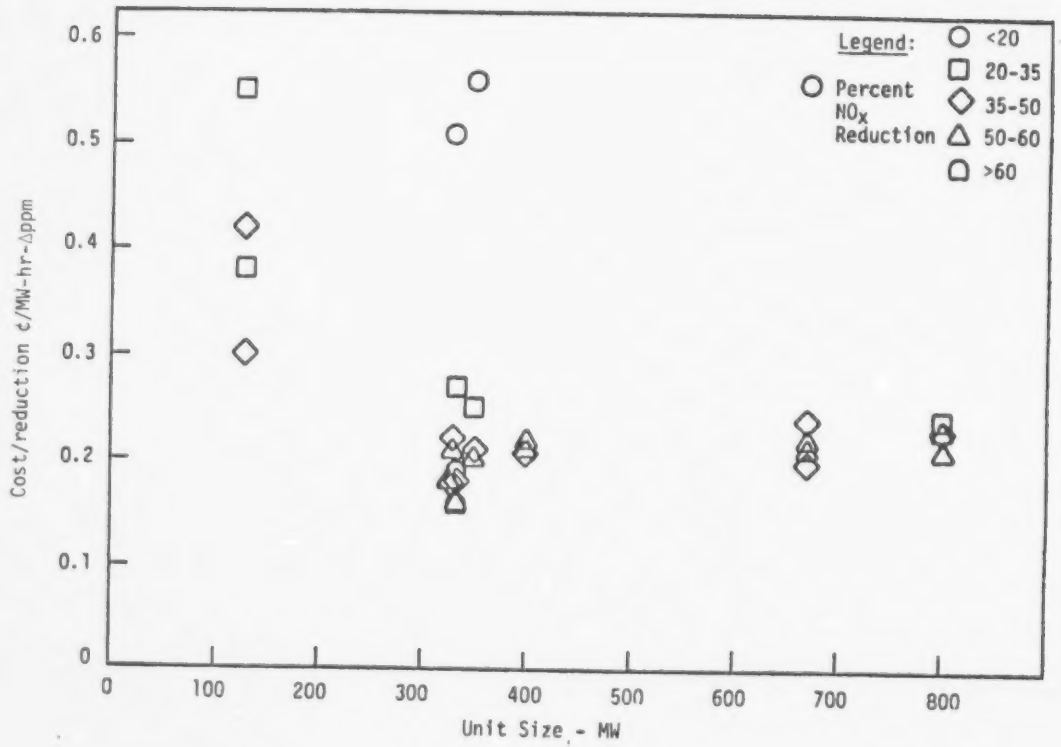

Figure 4-2. Normalized cost of NH_3 injection as a function of boiler size for both trim and maximum NO_x reduction targets.

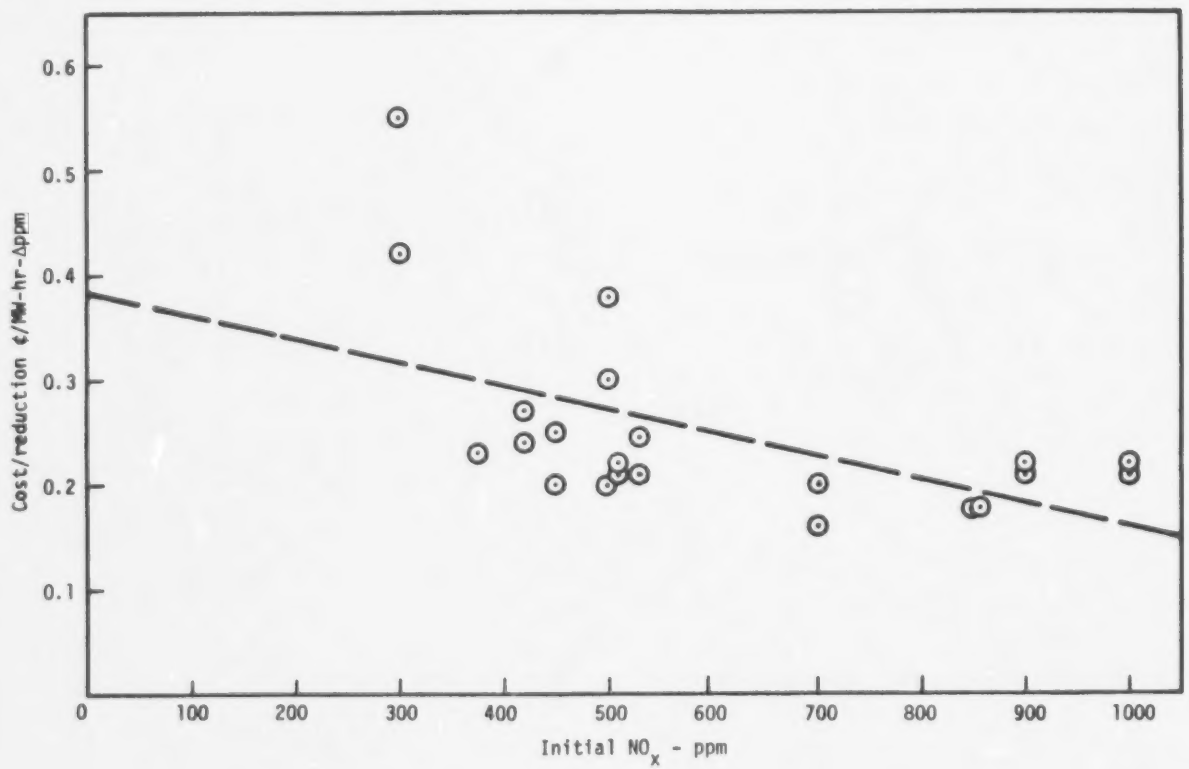

Figure 4-3. Normalized cost of NH_3 injection as a function of initial NO_x concentration.

decreases with lower initial NO_x concentration. Some of the effects noted may also be associated with unit size.

The total cost of the Thermal $DeNO_x$ Process as reported by Exxon was in the range of \$1.75 to \$6.1/kW-yr for all cases considered except for lignite where the costs were \$6.86 to \$8.61/kW-yr. The following sections highlight areas that should be addressed to represent more realistic costs.

4.1.1 Analysis of Assumptions and Procedures

The costing methodology used by Exxon does not clearly consider several costs which must be absorbed by the utility. Particularly, indirect capital costs, which cannot be attributable to specific hardware items, were not fully considered in this methodology. Most importantly, engineering, design, startup and contingencies, and license fee were not considered.

Allowance is not specifically made for engineering costs which must be considered because the retrofit design of the injection system is very site-specific. That is, the injection system must be developed to the needs of each unit and the intended mode of operation. Although preliminary estimates of applicability and NO_x reducing capability can be provided by reviewing the original equipment design specifications, accurate measurements should be made of flue gas temperatures and local conditions. Then, individual process designs must be developed based on such data. Accommodating flue gas temperature variations is important if high NO_x reductions are to be achieved. The system must accommodate flue gas temperature changes caused by load and operating variables and allow for fluctuations across the reaction zone caused by nonuniformities in flow and heat transfer. Money, must also be alloted for training of

operating personnel. These costs have not been included in Exxon's engineering costs.

The cost methodology should also include a construction contingency to account for uncertainties in the cost estimation including unforeseen escalation in cost terms, malfunctions, equipment design alterations, and other similar sources. The Total Erected Cost multiplier of 1.43 included in Exxon's installed cost estimates should account for field labor and construction field expenses, and field facilities for construction, services and utilities. However, this multiplier is probably not sufficient to account for system startup and shakedown and performance tests to ensure compliance with equipment performance guarantees. A license fee for the use of the patented process has also not been included in Exxon's reported costs. Information on these costs was not available at the time this report was written.

The annual costs of the $DeNO_x$ system is comprised of two components: operation and maintenance charges with associated overhead and capital charges. Exxon accounts for annual costs for ammonia, the compressed air carrier and the electricity required to operate the compressor. However, an additional part of the operational cost includes maintenance of the $DeNO_x$ process facility, cost of additional operating personnel to operate the facility, possible waste disposal from additional boiler water-washing, additional chemical analyses for byproduct and carryover, and support utilities for these functions. It is expected that the annual 20 percent of the initial investment should cover the cost of capital (depreciation taxes, insurance and interest) and some maintenance. However, it most likely will not cover all the indirect annual costs. Finally, administrative and plant overhead should be

included in the $DeNO_x$ estimates to account for additional expenses such as payroll, employee benefits, safety, and legal services.

These additional expenditures suggest a need for a systematic cost analysis procedure to account for all of the costs that the utility must face in installing a $DeNO_x$ facility. Acurex has developed such a procedure to include indirect costs such as engineering design and supervision and license fees which must be borne by the utility. Table 4-1 compares the cost items included in the Exxon and Acurex procedures respectively. The following section briefly describes some of the main features of this cost analysis procedure.

4.1.2 Acurex Cost Analysis Procedure

In an attempt to standardize costing for representative boiler design/fuel classifications, a standard cost analysis procedure was developed which attempts to account for all the costs a utility must bear in installing any NO_x control facility (Reference 4-2). This standardization facilitates comparisons from boiler to boiler for both conventional combustion modifications and Thermal $DeNO_x$. This cost analysis uses accepted estimation procedures based on advice from boiler manufacturers, utilities and equipment vendors.

To analyze control costs, regulated public utility economics were used. This was based on (Reference 4-3).

- Revenue Requirement -- (current operating disbursements + depreciation + interest paid on debt) = taxable income
- Taxable income x effective tax rate = income taxes
- Revenue Requirement = current operating disbursements + depreciation + income taxes + (fair return x rate base)

TABLE 4-1. COMPARISON OF EXXON AND ACUREX COST ANALYSES PROCEDURES

Cost Factor	Exxon Cost Estimating Procedure	Acurex Cost Analysis Procedure
Initial investment	• Hardware requirements • Installation labor and supervision • Construction field expense • Contractor's fee • Construction facilities • Service facilities • Utility facilities [a]	• Hardware requirements • Installation labor and supervision • Construction field expense • Contractor's fee • Construction facilities • Service facilities • Utility facilities • Engineering design and supervision • Engineering fee • Construction contingency • Initial charges (license costs) • Startup and performance tests
Direct annual operating costs	• Raw materials • Utilities (electricity for air compressors)	• Raw materials • Utilities (electricity for air compressors) • Additional operating personnel • Additional maintenance • Required analyses • Additional utilities
Annual indirect operating costs	• Capital charges for:[b] - Depreciation - Insurance - Replacements - Cost of capital and taxes	• Capital charges for: - Depreciation - Insurance - Replacements - Cost of capital and taxes • Administrative overhead • Plant overhead

[a]Cost multiplier: 1.43 times materials and labor = Total Erected Cost
[b]Annual capital charge is 20% of initial investment

An annualized cost methodology was developed, based on the revenue requirement approach, adapted from that used by the Tennessee Valley Authority in evaluating for EPA and EPRI, the cost of powerplant projects (References 4-4 and 4-5). This procedure has generally been accepted by industry (References 4-6 to 4-8). The revenue requirement for NO_x control is the incremental cost of operating the boiler under controlled conditions from the base conditions. This incremental cost includes the initial investment and the annual operating charges. After establishing the revenue requirement for each year (n) that the control is operated, up to N total years (where N is the remaining lifetime of the boiler), the annual cost can be evaluated. Basic economics defines the Annualized Revenue Requirements (ARR) as:

$$ARR = \frac{j\ (1+j)^N}{(1+j)^N - 1} \left[\sum_{n=1}^{N} \frac{RR\ (n)}{(1+j)^n} \right]$$

The first term is the capital recovery factor which discounts the money at the annual cost of capital (effective interest rate). The effective interest rate j is defined as

$$j = bi + (1-b)r$$

where b is the debt/equity ratio, i is the interest on borrowed money and r is the rate of return to equity. The debt/equity ratio for the utility industry has been fairly constant over the past few years with b = 0.5 as a representative value, according to the Edison Electric Institute (Reference 4-9). Interest rates i and r are given as 0.08 and 0.12 respectively for the year 1977 (References 4-4 and 4-5). The revenue requirements for each year (n) are the sum of the direct and indirect operating costs:

$$RR(n) = DOC + IOC(n)$$

Table 4-2 describes the components of the direct and indirect operating costs and the appropriate equations or estimating procedures for calculating all of these cost factors. Lim et al. give a more detailed description of this cost analysis procedure (Reference 4-2).

4.1.3 Control Costs Using Cost Analysis Procedure

To allow for comparison between Exxon's boiler cost estimates and the estimates derived from the cost analysis procedure, the same boiler designs and input conditions were assumed. It should be noted here that the actual hardware used for injecting the ammonia into the boiler was considered proprietary by Exxon. Thus, the cost of the original hardware could not be examined. This has limited our evaluation to indirect investment and annual costs.

The initial investment could vary significantly if there were problems such as poor access to the flue gas flow path, severe stratification or severe load following requirements and startup difficulties.

Table 4-3 lists the boiler design, NO_x reductions required, total hardware and labor costs, and raw materials needed for this cost analysis. Again, the maximum target was assumed with the assistance of combustion modifications (Exxon Case No. 4). Although the Exxon estimates of total hardware and labor for $DeNO_x$ installation were used in our analysis, the Total Erected Costs were not determined by multiplying material and labor by 1.43 as in the Exxon analysis, but rather, by considering each cost component separately (such as construction field expense and contractor fees). Additional initial costs considered separately were engineering design and supervision and fee, initial startup and performance testing and license fees. Standard estimating

TABLE 4-2. COST ANALYSIS CALCULATION ALGORITHM[a]

Cost Factor	Calculation Equation	Reference
Initial Investment, II	II = (DI + IND + SC + IC), as per below	
Engineering Design & Supervision, DS	DS estimated from preliminary design work	Lim et al. (Reference 4-2)
Engineering Fee, EFEE	EFEE = 0.08 x DS	Engineering Estimate
Hardware, TM	TM from preliminary design work	Vendor quotes
Installation Labor & Supervision, TL	TL from preliminary design work and engineering estimate	Lim et al. (Reference 4-2)
Construction Facilities, CF	CF = 0.05 x (TL + TM + UF + SF)	TVA (References 4-4, 4-5)
Service Facilities, SF	SF = 0.05 x (TL + TM)	TVA (References 4-4, 4-5)
Utilities Facilities, UF	UF = 0.03 x (TL + TM)	TVA (References 4-4, 4-5)
Construction Field Expense, CFE	CFE = 0.13 x (TL + TM + CF + SF + UF) = 0.13 x DI	TVA (References 4-4, 4-5)
Contractor's Fee, CON	CON = 0.07 x DI	TVA (References 4-4, 4-5)
Construction Contingency, CTN	CTN = 0.11 x DI	TVA (References 4-4, 4-5)
Initial Charges, IC	IC from input data (e.g., licensing fees, usually none)	LIM et al (Reference 4-2)
Startup Costs, SC	SC = 0.10 x (DI + DS + EFEE + CFE + CON + CTN) = 0.10 x (DI + IND)	TVA (References 4-4, 4-5)
Indirect Operating Costs, IOC(n)	IOC(n) = CC(n) + CCLOST(n) + OH	
Capital Charge, CC(n)	CC(n) = D + IN + RE + CCT(n)	
Depreciation, D	D = II/N	Straight line depreciation
Insurance, IN	IN = 0.005 x II	TVA (References 4-4, 4-5)
Replacements, RE	RE = 0.004 x II	
Cost of Capital and Taxes, CCT(n)	$CCT(n) = \left[ib + r(1 - b) + \frac{t}{1 - t}(1 - b)r \right] . ODB(n)$ where t = effective tax rate = s + (1-s)f and s = state tax rate f = federal tax rate and ODB = II - (n-1)D	Lim et al. (Reference 4-2)

[a]A glossary of terms appears in Appendix A.

TABLE 4-2. Concluded

Cost Factor	Calculation Equation	Reference
Capital charges of Lost Capacity, CCLOST (n)	Calculated analogously to CC(n), only use $\left(\text{IIO} \times \frac{\text{DRATE}}{\text{KW}}\right)$ in place of II where IIO = Initial investment of boiler DRATE = Power derate with controls, if necessary KW = Power rating of boiler before control	Lim et al. (Reference 4-2)
Overhead		
Administrative overhead, OHA	OHA = 0.10 x OLS	TVA (References 4-4, 4-5)
Plant overhead, OHP	OHP = 0.20 x (OLS + UC + M + A), as indicated below	TVA (References 4-4, 4-5)
Direct Operating Costs, DOC		
Fuel Penalty, AF	AF = HYR x HRATE x (KW - DRATE) x FCOST x FPEN where HYR = Annual operating hours	Engineering estimate
Fuel Credit, FC	FC = HYR x HRATE x DRATE x FCOST	Engineering estimate
Raw materials, RM	RM from input data where HRATE = Heat rate of boiler FCOST = Fuel cost	Engineering estimate
Conversions Costs		
Additional operating personnel, OLS	OLS from engineering estimate	
Additional utilities, UC	UC from engineering estimate	
Additional maintenance, M	M = 0.05 x TLM	TVA (References 4-4, 4-5)
Required analyses, A	A from engineering estimate	Reference 4-10
Annual royalties, AROY	AROY from input data	Reference 4-10
Purchased Power, PP	PP = DRATE x HYR x PPR where PPR = purchased power rate	Engineering estimate
Annualized Cost to Control, ARRU	$\text{ARRU} = \frac{j(1+j)^N}{(1+j)^N - 1}\left[\sum_{n=1}^{N} \frac{\text{DOC} + \text{IOC}(n)}{(1+j)^n}\right] \cdot \frac{1}{(\text{KW} - \text{DRATE})}$	Lim et al. (Reference 4-2)

TABLE 4-3. INPUT DATA TO COST ANALYSIS PROCEDURE (EXXON CASE NO. 4)

Unit	CM Controlled NO_x Level (PPM)	Final NO_x Level (PPM)	Flue Gas Rate (Mg/hr)	NH_3 Rate (Mg/yr)[a]	Carrier Rate (MSCM/yr)	NH_3 Cost ($/yr)[b]	Carrier Cost ($/yr)[c]	Hardware and Labor Cost
B&W 130 MW subbituminous	300	225	579	452	50.25	84,490	72,750	778,300
B&W 333 MW bituminous	420	300	1,353	1,432	117.48	267,750	170,100	1,128,000
B&W 400 MW lignite	900	300	2,294	TARGET CANNOT BE MET				
CE 350 MW bituminous	450	300	1,459	1,736	126.64	324,570	183,360	1,171,400
CE 800 MW subbituminous	375	225	3,941	4,703	342.17	879,410	495,419	1,715,400
FW 330 MW bituminous	510	300	1,376	2,900	119.49	542,402	173,007	1,190,200
FW 670 MW subbituminous	420	225	3,716	6,319	332.62	1,181,670	467,113	1,690,900
RS 350 MW bituminous	420	300	1,792	1,929	155.56	360,510	225,238	1,206,300

[a] 80% load factor.

[b] $187/ton

[c] $14.48/10,000 SCM

procedure suggests a construction contingency of up to 30 percent of the direct investment costs (Reference 4-11). A conservative estimate of 20 percent for construction contingency was used for the Acurex cost analysis. It is reasonable to include this cost to allow for uncertainties such as escalation in cost items, equipment design alterations, and other unforeseen costs.

The direct operating cost for ammonia was again costed as $187/Mg ($170/ton) and carrier cost at $14.48/10,000 SCM ($0.41/10,000 SCF). However, additional direct operating cost components such as maintenance, operating personnel and royalties were considered separately in the costing procedure. Capital charges were based on a straight annual charge of 20 percent of the initial investment, but rather, calculated as follows:

Taxable Income = (Return on Equity) + (Tax Deductable Interest on Borrowed Money) + (Tax Deductable Depreciation) + (Money for Taxes).

Where the cost of capital and taxes in year n is given by:

$$CCT(n) = ib + r\,(1-b) + \frac{t}{1-t}\,(1-b)r \quad ODB(n)$$

and should be annualized as

$$ACCT = \frac{j(1+j)^N}{(1+j)^N-1} \sum_{n=1}^{N} \frac{CCT(n)}{(1+j)^n}$$

where

$j = ib + r(1-b)$ = effective interest rate

t = effective tax rate

$ODB(n)$ = outstanding depreciation rate in the year n

N = remaining lifetime of the boiler

For further discussion of these procedures and their derivation, see Reference 4-2.

Finally, indirect operating costs for plant and administrative overhead were included to account for expenses such as payroll, benefits, and safety programs. Appendix B lists the cost input data for the eight coal-fired boiler types for the case of maximum reduction with combustion modifications. These costs result from the Exxon inputs for hardware, labor, and raw materials shown in Table 4-3 and the assumptions made in the cost analysis procedure of Section 4.1.2. A glossary of terms used in the procedure are given in Appendix A. Tables 4-4 to 4-10 list the annualized control costs for the eight coal-fired boiler types using the cost inputs listed in Appendix B and the cost procedure. It is assumed that retrofit applications are completed during normal outage periods so that additional downtime is not required.

For control cost projections purposes, the results shown are only valid at best to two significant figures. These control costs shown in Tables 4-4 to 4-10 do not include the cost of annual royalties and cost of combustion modifications. Annual royalties are not known and thus were not included. Table 4-11 lists the total cost of the Thermal DeNO$_x$ Process including the cost of combustion modifications.

4.1.4 Comparison of Cost Results

A comparison was made between the retrofit costs obtained by Exxon and costs obtained by Acurex for the deep NO$_x$ reduction case. Table 4-12 lists the direct and indirect operating costs for all the coal-fired boilers considered except for the lignite-fired cyclone for which deep reductions could not be reached. As indicated by the data in the cost column the contingency costs considered by Acurex increased Exxon's

TABLE 4-4. COST BREAKDOWN OF NH_3 INJECTION ON 130 MW FRONT WALL COAL-FIRED BOILER

MAXIMUM CONTINUOUS RATING (MW) : 130.
TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2) : 300.
TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) : 225.

DERATE REQUIRED (MW) : NONE

FUEL PENALTY (PERCENT) : .0000

ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

INITIAL INVESTMENT ($/KW) : 10.44

ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) : 1.784

ANNUALIZED DIRECT OPERATING COST ($/KW-YR) : 1.573

ANNUALIZED COST TO CONTROL ($/KW-YR) : 3.357

INITIAL INVESTMENT ($)	
ENGINEERING DESIGN & SUPERVISION	39717.
ENGINEERING FEE	3177.
HARDWARE	778300.
INSTALLATION LABOR & SUPERVISION	0.
CONSTRUCTION FACILITIES	42028.
SERVICE FACILITIES	38915.
UTILITIES FACILITIES	23349.
CONSTRUCTION FIELD EXPENSE	114737.
CONTRACTORS FEE	61781.
CONSTRUCTION CONTINGENCY	132389.
INITIAL CHARGES	0.
STARTUP COSTS	123439.
TOTAL INITIAL INVESTMENT	1357833.
ANNUALIZED OPERATING COST ($/YR)	
INDIRECT OPERATING COSTS	
CAPITAL CHARGES	
DEPRECIATION	54313.
INSURANCE	6789.
REPLACEMENT COSTS	5431.
COST OF CAPITAL & TAXES	155062.
CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)	
DEPRECIATION	0.
INSURANCE	0.
REPLACEMENT COSTS	0.
COST OF CAPITAL & TAXES	0.
OVERHEAD	
ADMINISTRATIVE OVERHEAD	833.
PLANT OVERHEAD	9449.
DIRECT OPERATING COSTS	
FUEL COST PENALTY	0.
FUEL CREDIT (FOR UNUSED FUEL IF DERATE)	(0.)
RAW MATERIALS	157240.
CONVERSION COSTS	
ADDITIONAL OPERATING PERSONNEL	8330.
ADDITIONAL UTILITIES REQUIREMENTS	0.
ADDITIONAL MAINTENANCE	38915.
REQUIRED ANALYSES	0.
ANNUAL ROYALTIES	0.
PURCHASED POWER (IF DERATE)	0.
TOTAL ANNUALIZED OPERATING COSTS	436363.
ANNUALIZED COST TO CONTROL ($/KW-YR)	3.36

TABLE 4-5. COST BREAKDOWN OF NH_3 INJECTION ON 333 MW HORIZONTALLY OPPOSED COAL-FIRED BOILER

MAXIMUM CONTINUOUS RATING (MW) : 333.
TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2) : 420.
TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) : 300.

DERATE REQUIRED (MW) : NONE

FUEL PENALTY (PERCENT) : .0000

ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

INITIAL INVESTMENT ($/KW) : 5.910

ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) : 1.006

ANNUALIZED DIRECT OPERATING COST ($/KW-YR) : 1.509

ANNUALIZED COST TO CONTROL ($/KW-YR) : 2.515

INITIAL INVESTMENT ($)	
ENGINEERING DESIGN & SUPERVISION	57562.
ENGINEERING FEE	4605.
HARDWARE	1128000.
INSTALLATION LABOR & SUPERVISION	0.
CONSTRUCTION FACILITIES	60912.
SERVICE FACILITIES	56400.
UTILITIES FACILITIES	33840.
CONSTRUCTION FIELD EXPENSE	166290.
CONTRACTORS FEE	89541.
CONSTRUCTION CONTINGENCY	191873.
INITIAL CHARGES	0.
STARTUP COSTS	178902.
TOTAL INITIAL INVESTMENT	1967924.

ANNUALIZED OPERATING COST ($/YR)	
INDIRECT OPERATING COSTS	
CAPITAL CHARGES	
DEPRECIATION	78717.
INSURANCE	9840.
REPLACEMENT COSTS	7872.
COST OF CAPITAL & TAXES	224733.
CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)	
DEPRECIATION	0.
INSURANCE	0.
REPLACEMENT COSTS	0.
COST OF CAPITAL & TAXES	0.
OVERHEAD	
ADMINISTRATIVE OVERHEAD	833.
PLANT OVERHEAD	12946.
DIRECT OPERATING COSTS	
FUEL COST PENALTY	0.
FUEL CREDIT (FOR UNUSED FUEL IF DERATE)	(0.)
RAW MATERIALS	437850.
CONVERSION COSTS	
ADDITIONAL OPERATING PERSONNEL	8330.
ADDITIONAL UTILITIES REQUIREMENTS	0.
ADDITIONAL MAINTENANCE	56400.
REQUIRED ANALYSES	0.
ANNUAL ROYALTIES	0.
PURCHASED POWER (IF DERATE)	0.
TOTAL ANNUALIZED OPERATING COSTS	837521.
ANNUALIZED COST TO CONTROL ($/KW-YR)	2.52

TABLE 4-6. COST BREAKDOWN OF NH_3 INJECTION ON 350 MW TANGENTIAL COAL-FIRED BOILER

MAXIMUM CONTINUOUS RATING (MW) : 350.
TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2) : 450.
TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) : 300.

DERATE REQUIRED (MW) : NONE

FUEL PENALTY (PERCENT) : .0000

ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

INITIAL INVESTMENT ($/KW) : 5.839

ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) : .9935

ANNUALIZED DIRECT OPERATING COST ($/KW-YR) : 1.642

ANNUALIZED COST TO CONTROL ($/KW-YR) : 2.636

INITIAL INVESTMENT ($)	
ENGINEERING DESIGN & SUPERVISION	59777.
ENGINEERING FEE	4782.
HARDWARE	1171400.
INSTALLATION LABOR & SUPERVISION	0.
CONSTRUCTION FACILITIES	63256.
SERVICE FACILITIES	58570.
UTILITIES FACILITIES	35142.
CONSTRUCTION FIELD EXPENSE	172688.
CONTRACTORS FEE	92986.
CONSTRUCTION CONTINGENCY	199255.
INITIAL CHARGES	0.
STARTUP COSTS	185785.
TOTAL INITIAL INVESTMENT	2043640.

ANNUALIZED OPERATING COST ($/YR)	
INDIRECT OPERATING COSTS	
CAPITAL CHARGES	
DEPRECIATION	81746.
INSURANCE	10218.
REPLACEMENT COSTS	8175.
COST OF CAPITAL & TAXES	233380.
CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)	
DEPRECIATION	0.
INSURANCE	0.
REPLACEMENT COSTS	0.
COST OF CAPITAL & TAXES	0.
OVERHEAD	
ADMINISTRATIVE OVERHEAD	833.
PLANT OVERHEAD	13380.
DIRECT OPERATING COSTS	
FUEL COST PENALTY	0.
FUEL CREDIT (FOR UNUSED FUEL IF DERATE)	(0.)
RAW MATERIALS	507930.
CONVERSION COSTS	
ADDITIONAL OPERATING PERSONNEL	8330.
ADDITIONAL UTILITIES REQUIREMENTS	0.
ADDITIONAL MAINTENANCE	58570.
REQUIRED ANALYSES	0.
ANNUAL ROYALTIES	0.
PURCHASED POWER (IF DERATE)	0.
TOTAL ANNUALIZED OPERATING COSTS	922561.
ANNUALIZED COST TO CONTROL ($/KW-YR)	2.64

TABLE 4-7. COST BREAKDOWN OF NH_3 INJECTION ON 800 MW TANGENTIAL COAL-FIRED BOILER

MAXIMUM CONTINUOUS RATING (MW) : 800.
TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2) : 375.
TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) : 225.

DERATE REQUIRED (MW) : NONE

FUEL PENALTY (PERCENT) : .0000

ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

INITIAL INVESTMENT ($/KW) : 3.741

ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) : .6351

ANNUALIZED DIRECT OPERATING COST ($/KW-YR) : 1.836

ANNUALIZED COST TO CONTROL ($/KW-YR) : 2.471

DATE

INITIAL INVESTMENT ($)	
ENGINEERING DESIGN & SUPERVISION	87537.
ENGINEERING FEE	7003.
HARDWARE	1715400.
INSTALLATION LABOR & SUPERVISION	0.
CONSTRUCTION FACILITIES	92632.
SERVICE FACILITIES	85770.
UTILITIES FACILITIES	51462.
CONSTRUCTION FIELD EXPENSE	252884.
CONTRACTORS FEE	136168.
CONSTRUCTION CONTINGENCY	291790.
INITIAL CHARGES	0.
STARTUP COSTS	272065.
TOTAL INITIAL INVESTMENT	2992710.
ANNUALIZED OPERATING COST ($/YR)	
INDIRECT OPERATING COSTS	
CAPITAL CHARGES	
DEPRECIATION	119708.
INSURANCE	14964.
REPLACEMENT COSTS	11971.
COST OF CAPITAL & TAXES	341762.
CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)	
DEPRECIATION	0.
INSURANCE	0.
REPLACEMENT COSTS	0.
COST OF CAPITAL & TAXES	0.
OVERHEAD	
ADMINISTRATIVE OVERHEAD	833.
PLANT OVERHEAD	18820.
DIRECT OPERATING COSTS	
FUEL COST PENALTY	0.
FUEL CREDIT (FOR UNUSED FUEL IF DERATE)	(0.)
RAW MATERIALS	1374829.
CONVERSION COSTS	
ADDITIONAL OPERATING PERSONNEL	8330.
ADDITIONAL UTILITIES REQUIREMENTS	0.
ADDITIONAL MAINTENANCE	85770.
REQUIRED ANALYSES	0.
ANNUAL ROYALTIES	0.
PURCHASED POWER (IF DERATE)	0.
TOTAL ANNUALIZED OPERATING COSTS	1976987.
ANNUALIZED COST TO CONTROL ($/KW-YR)	2.47

TABLE 4-8. COST BREAKDOWN OF NH_3 INJECTION ON 330 MW FRONT WALL COAL-FIRED BOILER

MAXIMUM CONTINUOUS RATING (MW) : 330.
TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2) : 510.
TYPICAL CONTROLLED NOx EMISSION (PPM AT 3% O2) : 300.

DERATE REQUIRED (MW) : NONE

FUEL PENALTY (PERCENT) : .0000

ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

INITIAL INVESTMENT ($/KW) : 6.292

ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) : 1.071

ANNUALIZED DIRECT OPERATING COST ($/KW-YR) : 2.373

ANNUALIZED COST TO CONTROL ($/KW-YR) : 3.444

INITIAL INVESTMENT ($)	
ENGINEERING DESIGN & SUPERVISION	60736.
ENGINEERING FEE	4859.
HARDWARE	1190200.
INSTALLATION LABOR & SUPERVISION	0.
CONSTRUCTION FACILITIES	64271.
SERVICE FACILITIES	59510.
UTILITIES FACILITIES	35706.
CONSTRUCTION FIELD EXPENSE	175459.
CONTRACTORS FEE	94478.
CONSTRUCTION CONTINGENCY	202453.
INITIAL CHARGES	0.
STARTUP COSTS	188767.
TOTAL INITIAL INVESTMENT	2076439.

ANNUALIZED OPERATING COST ($/YR)	
INDIRECT OPERATING COSTS	
CAPITAL CHARGES	
DEPRECIATION	83058.
INSURANCE	10382.
REPLACEMENT COSTS	8306.
COST OF CAPITAL & TAXES	237126.
CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)	
DEPRECIATION	0.
INSURANCE	0.
REPLACEMENT COSTS	0.
COST OF CAPITAL & TAXES	0.
OVERHEAD	
ADMINISTRATIVE OVERHEAD	833.
PLANT OVERHEAD	13568.
DIRECT OPERATING COSTS	
FUEL COST PENALTY	0.
FUEL CREDIT (FOR UNUSED FUEL IF DERATE)	(0.)
RAW MATERIALS	715409.
CONVERSION COSTS	
ADDITIONAL OPERATING PERSONNEL	8330.
ADDITIONAL UTILITIES REQUIREMENTS	0.
ADDITIONAL MAINTENANCE	59510.
REQUIRED ANALYSES	0.
ANNUAL ROYALTIES	0.
PURCHASED POWER (IF DERATE)	0.
TOTAL ANNUALIZED OPERATING COSTS	1136521.
ANNUALIZED COST TO CONTROL ($/KW-YR)	3.44

TABLE 4-9. COST BREAKDOWN OF NH_3 INJECTION ON 670 MW HORIZONTALLY OPPOSED COAL-FIRED BOILER

MAXIMUM CONTINUOUS RATING (MW) : 670.
TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2) : 420.
TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) : 225.

DERATE REQUIRED (MW) : NONE

FUEL PENALTY (PERCENT) : .0000

ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

INITIAL INVESTMENT ($/KW) : 4.403

ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) : .7475

ANNUALIZED DIRECT OPERATING COST ($/KW-YR) : 2.599

ANNUALIZED COST TO CONTROL ($/KW-YR) : 3.347

INITIAL INVESTMENT ($)	
ENGINEERING DESIGN & SUPERVISION	86287.
ENGINEERING FEE	6903.
HARDWARE	1690900.
INSTALLATION LABOR & SUPERVISION	0.
CONSTRUCTION FACILITIES	91309.
SERVICE FACILITIES	84545.
UTILITIES FACILITIES	50727.
CONSTRUCTION FIELD EXPENSE	249272.
CONTRACTORS FEE	134224.
CONSTRUCTION CONTINGENCY	287622.
INITIAL CHARGES	0.
STARTUP COSTS	268179.
TOTAL INITIAL INVESTMENT	2949967.

ANNUALIZED OPERATING COST ($/YR)	
INDIRECT OPERATING COSTS	
CAPITAL CHARGES	
DEPRECIATION	117999.
INSURANCE	14750.
REPLACEMENT COSTS	11800.
COST OF CAPITAL & TAXES	336881.
CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)	
DEPRECIATION	0.
INSURANCE	0.
REPLACEMENT COSTS	0.
COST OF CAPITAL & TAXES	0.
OVERHEAD	
ADMINISTRATIVE OVERHEAD	833.
PLANT OVERHEAD	18575.
DIRECT OPERATING COSTS	
FUEL COST PENALTY	0.
FUEL CREDIT (FOR UNUSED FUEL IF DERATE)	(0.)
RAW MATERIALS	1648783.
CONVERSION COSTS	
ADDITIONAL OPERATING PERSONNEL	8330.
ADDITIONAL UTILITIES REQUIREMENTS	0.
ADDITIONAL MAINTENANCE	84545.
REQUIRED ANALYSES	0.
ANNUAL ROYALTIES	0.
PURCHASED POWER (IF DERATE)	0.
TOTAL ANNUALIZED OPERATING COSTS	2242495.
ANNUALIZED COST TO CONTROL ($/KW-YR)	3.35

TABLE 4-10. COST BREAKDOWN OF NH_3 INJECTION ON 350 MW TURBO COAL-FIRED BOILER

MAXIMUM CONTINUOUS RATING (MW) : 350.
TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2) : 420.
TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) : 300.

DERATE REQUIRED (MW) : NONE

FUEL PENALTY (PERCENT) : .0000

ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

INITIAL INVESTMENT ($/KW) : 6.013

ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) : 1.023

ANNUALIZED DIRECT OPERATING COST ($/KW-YR) : 1.870

ANNUALIZED COST TO CONTROL ($/KW-YR) : 2.893

INITIAL INVESTMENT ($)	
ENGINEERING DESIGN & SUPERVISION	61557.
ENGINEERING FEE	4925.
HARDWARE	1206300.
INSTALLATION LABOR & SUPERVISION	0.
CONSTRUCTION FACILITIES	65140.
SERVICE FACILITIES	60315.
UTILITIES FACILITIES	36189.
CONSTRUCTION FIELD EXPENSE	177833.
CONTRACTORS FEE	95756.
CONSTRUCTION CONTINGENCY	205192.
INITIAL CHARGES	0.
STARTUP COSTS	191321.
TOTAL INITIAL INVESTMENT	2104527.

ANNUALIZED OPERATING COST ($/YR)		
INDIRECT OPERATING COSTS		
CAPITAL CHARGES		
DEPRECIATION		84181.
INSURANCE		10523.
REPLACEMENT COSTS		8418.
COST OF CAPITAL & TAXES		240333.
CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)		
DEPRECIATION		0.
INSURANCE		0.
REPLACEMENT COSTS		0.
COST OF CAPITAL & TAXES		0.
OVERHEAD		
ADMINISTRATIVE OVERHEAD		833.
PLANT OVERHEAD		13729.
DIRECT OPERATING COSTS		
FUEL COST PENALTY		0.
FUEL CREDIT (FOR UNUSED FUEL IF DERATE)	(	0.)
RAW MATERIALS		585748.
CONVERSION COSTS		
ADDITIONAL OPERATING PERSONNEL		8330.
ADDITIONAL UTILITIES REQUIREMENTS		0.
ADDITIONAL MAINTENANCE		60315.
REQUIRED ANALYSES		0.
ANNUAL ROYALTIES		0.
PURCHASED POWER (IF DERATE)		0.
TOTAL ANNUALIZED OPERATING COSTS		1012410.
ANNUALIZED COST TO CONTROL ($/KW-YR)		2.89

TABLE 4-11. TOTAL COST OF THE THERMAL $DeNO_x$ PROCESS FROM COST ANALYSIS PROCEDURE -- CASE NO. 4

Unit	Thermal $DeNO_x$ Cost W/O License Fee $/kw-yr	Combustion[a] Modification	Cost of Combustion[a] Modification $/kw-yr	Total Cost	
				$/kw-yr	mills/kw-hr[b]
B&W 130 MW	3.36	LNB[c]	0.40	3.76	0.53
B&W 333 mw	2.52	LNB	0.40	2.92	0.42
B&W 400 MW	Target not achievable -- this unit excluded				
CE 350 MW	2.64	OFA[d]	0.53	3.17	0.45
CE 800 MW	2.47	OFA	0.53	3.00	0.43
FW 330 MW	3.44	LNB	0.40	3.84	0.55
FW 670 MW	3.35	LNB	0.40	3.75	0.54
RS 350 MW	2.89	OFA	0.69	3.58	0.52

[a]Information from Reference 4-2
[b]80 percent load factor
[c]LNB = low NO_x burners
[d]OFA = overfire air injection

TABLE 4-12. THERMAL DeNO$_x$ COST COMPARISON FOR THE MAXIMUM NO$_x$ REDUCTION -- CASE NO. 4

Unit	Exxon Cost mills/kw-hr		Acurex Cost mills/kw-hr		Acurex Cost of Combustion Modification mills/kw-hr	Total Cost mills/kw-hr		Percent Increase
	Direct Operating	Indirect Operating	Direct Operating	Indirect Operating		Exxon	Acurex	
B&W 130 MW	0.17	0.24	0.22	0.25	0.06	0.47	0.53	13
B&W 333 MW	0.18	0.14	0.22	0.14	0.06	0.38	0.42	11
CE 350 MW	0.20	0.14	0.23	0.14	0.08	0.42	0.45	7
CE 800 MW	0.25	0.09	0.26	0.09	0.08	0.42	0.43	2
FW 300 MW	0.30	0.14	0.34	0.15	0.06	0.50	0.55	10
FW 670 MW	0.35	0.10	0.37	0.11	0.06	0.51	0.54	6
RS 350 MW	0.24	0.14	0.27	0.15	0.10	0.48	0.52	8
Average	0.24	0.14	0.27	0.15	0.07	0.45	0.49	9

estimated cost by approximately 9 percent on the average. The largest differences are evidenced in the direct operating cost. This increase is specifically caused by consideration of such factors as:

- Additional maintenance
- Additional operating personnel
- Required analysis
- Plant and administrative overhead.

These factors increased the direct operating cost estimated by Acurex by approximately 13 percent on the average. Annual royalties should also be added to these costs; thus the total operating cost would further increase above the level reported here. The average indirect operating cost estimated here is only approximately 7 percent larger than the cost calculated by Exxon. This increase is primarily due to startup and performance costs.

In general, the total operating cost (direct and indirect) reported here is probably more representative of the actual cost incurred by utilities in retrofitting Thermal $DeNO_x$ on coal-fired utility boilers. The data in Table 4-12 also indicates that the cost of NH_3 injection ranges from 80 to 90 percent of the total combined control cost. Combustion modifications account for the remaining 10 to 20 percent.

4.2 IMPACT OF FULL SCALE THERMAL $DeNO_x$ IMPLEMENTATION ON AMMONIA COST AND SUPPLY

The cost of the $DeNO_x$ Process is highly sensitive to the cost of ammonia. This section evaluates factors which may perturb the cost of ammonia and considers the impact on national fuel supply.

Approximately 64 percent of the current world ammonia is being produced from natural gas, 13 percent from naptha, 12 percent from coal or

coke, with the remaining 11 percent divided among other feedstock sources. Typically, 75 percent of ammonia is used for fertilizer and feeds, 9 percent for fiber and plastic intermediates, 4 percent for explosives and 11 percent for other miscellaneous industries (Reference 4-12).

Production of synthetic ammonia in the United States during the year ending 30 June 1976 was estimated at 15.9×10^6 Mg (17.5 million tons) (Reference 4-13). However, capacity additions during the past 2 years should raise the domestic capacity to almost 17.3×10^6 Mg (19.0 million tons) annually. This increase is largely being brought about by the construction of plants in the range of 900 to 1360 Mg/day (1000 to 1500 tons/day) which use a light hydrocarbon feedstock with the partial oxidation process. U.S. ammonia demand in 1980 is estimated to reach 19.4×10^6 Mg (21.3 million tons). Ammonia for agriculture will be responsible for 70 percent of that demand (Reference 4-14).

In 1976 ammonia was available at about \$132/Mg (\$129/ton). However, that ammonia price may vary by as much as 50 percent by region. This cost is lower than the current list price of \$187/Mg (\$170/ton) and well below the price of up to \$290/Mg (\$264/ton) in 1975. Figure 4-4 shows that the historical price of ammonia has been highly unstable primarily because of governing supply and demand and other influences such as the cost of feedstock fuels.

4.2.1 Methods for Producing Ammonia

Based on raw material availability, the choice of a process design is between catalytic steam reforming of light hydrocarbons and partial oxidation of heavy hydrocarbons. In exceptional cases, where hydrogen

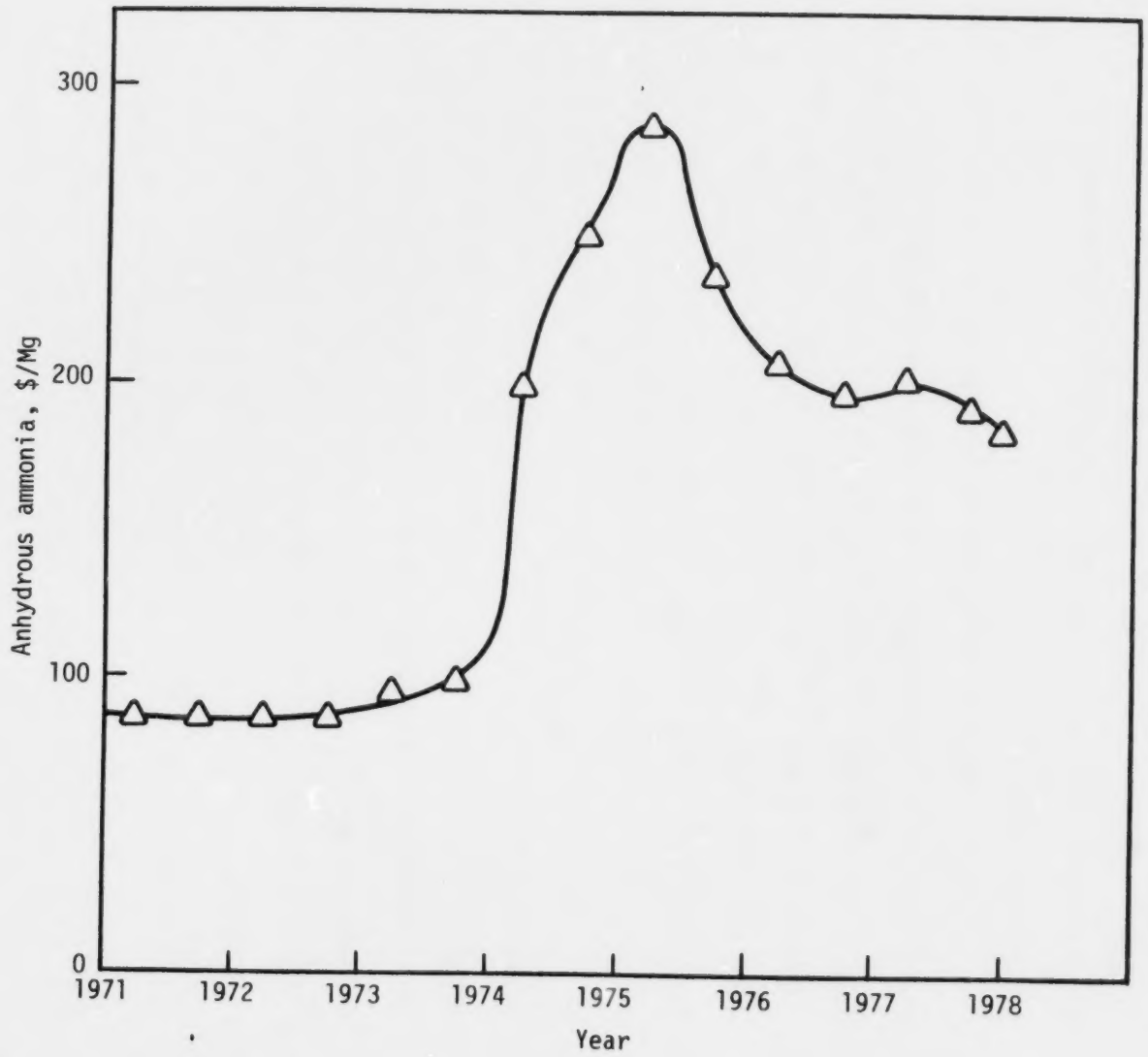

Figure 4-4. Historical trends of ammonia prices.

rich gas is available, cryogenic processing or some alternate process for purifying hydrogen is used.

Catalytic Steam Reforming

This process consists of desulfurization, primary and secondary reforming to generate raw gas, CO shift conversion, CO_2 removal, methanation of residual CO, and finally, conversion to ammonia.

Partial Oxidation

Reforming requires catalysts for the raw gas generation step. With the partial oxidation processes, raw synthesis gas is generated noncatalytically at relatively high temperature and pressure in conjunction with use of high purity oxygen in the combustion step. Two major processes are available: one from Shell Development Company, and the other from Texaco Development Corporation. The partial oxidation process can be used for both gaseous and liquid feedstocks (Reference 4-15).

Several raw gas treating techniques can be employed with the partial oxidation process including cryogenic treatment, gas generation at lower pressure, and catalytic procedures. The decision to employ one of these methods is based on gas generation pressure, the energy balance, and whether cryogenic or gas treatment is used for the gas purification step. These alternatives can all be adapted to both the Shell and Texaco processes.

4.2.2 Supply and Availability of Natural Gas

As mentioned earlier in this section, the majority of ammonia is currently synthesized from natural gas. However, natural gas reserves will become increasingly scarce in the future, and naptha and fuel oil, which could replace natural gas, are either too scarce or expensive. Thus, coal has the best potential as an alternate feedstock for ammonia

synthesis. Several other factors that are responsible for this development are:

- Present cutbacks in natural gas: Ammonia manufacturers are experiencing natural gas cutbacks during the winter months. The risks of even larger cutbacks threaten the profitability of natural gas based ammonia plants.
- Long term coal supplies: Long term coal supplies can be secured at a relatively stable price. Thus, the effects of inflation and price escalation are minimized.
- Coal can increase natural gas supply: It is more economical to increase available natural gas supplies by building coal-based ammonia plants than by building coal-based Substitute Natural Gas (SNG) plants.

However, it has been estimated that using ammonia to reduce NO_x would require a 20 to 30 percent increase in ammonia production (Reference 4-16). Moreover, switching to coal may impact the price of ammonia and the coal supply picture. To address these concerns, the following discussion considers how much ammonia is needed for specific boiler types to reach the low NSPS target. Then, the amount and comparative costs of natural gas and coal feedstocks are evaluated and its impact on national fuel consumption is considered.

Hydrogen injection is not seen as a tenable solution for control of $DeNO_x$ reaction temperature because of cost considerations, safety factors and storage requirements, and thus, this option is not considered. Since ammonia injection is nearly an order of magnitude more expensive than conventional combustion controls for most cases, hydrogen injection would further increase this disparity in costs. However,

hydrogen may prove to be an effective tuning technique for nonconventional combustion configurations which cannot be adapted to isothermal cavity or in-tube-bank injection.

4.2.3 Ammonia Requirements for Specific Boiler Types

Exxon's ammonia injection rate estimates were used to determine the amount of ammonia needed for each boiler type. An ammonia cost of $187/Mg ($170/ton) was assumed to arrive at the cost estimates. The NO_x reductions were based on the low NSPS targets (172 ng/J for bituminous and 129 ng/J for subbituminous coal) in conjunction with conventional combustion modification controls. The low NO_x targets were employed since by the time $DeNO_x$ would be fully implemented, these low targets would be reasonable standards (1980-85 timeframe) (Reference 4-17). However, this is a worst-case analysis since it is unlikely that all new, as well as existing, boilers will have to meet this standard.

Table 4-13 shows the ammonia required and cost per MW-hr for the four boiler types. The amount of ammonia required does not appear to be a function of the equipment type (tangential, wall fired, etc.) but rather, a function of the relative levels of initial and final NO_x emission levels. That is, if the difference between the combustion modification controlled NO_x level and the final emission level is large, then the ammonia required (kg/MW-hr) is also large.

Based on representative costs from Table 4-13, the national ammonia supply and total costs for 1985 were determined using high and low coal energy scenarios and the low emissions target (Reference 4-17). Table 4-14 shows that for the high coal consumption cases, as much as $650 million would be spent for ammonia if all coal-fired utility boilers were retrofit with $DeNO_x$ controls. In addition, about 3.8×10^6 Mg of ammonia would

TABLE 4-13. AMOUNT AND COST OF AMMONIA USAGE FOR THE EIGHT COAL-FIRED UTILITY BOILERS

Boiler Type	Manufacturer	Capacity (MW)	Baseline Emissions (ppm)	CM[a] Controlled (ppm)	CM+ $DeNO_x$ Controlled (ppm)	NH_3 kgs/ hr	NH_3 kgs/ MW-hr	Cost of Ammonia	
								$/hr	$/MW-hr
Tangential	CE	350	500	450	300	248	0.70	46.4	0.13
	CE	800	530	375	225	672	0.84	125.6	0.16
Single Wall	B&W	130	500	300	225	65	0.50	13.07	0.09
	FW	330	850	510	300	414	1.25	77.5	0.23
Opposed Wall and Turbo Furnace	B&W	333	700	420	300	204	0.61	38.3	0.12
	FW	670	700	420	225	903	1.35	168.8	0.25
	RS	350	700	420	300	275	0.79	51.5	0.15
Cyclone[b]	B&W	400	1000	1000	430	2031	5.08	379.8	0.95

[a]CM = Combustion modification

[b]Assume no combustion modifications, max NO_x reduction of 57% with $DeNO_x$.

TABLE 4-14. TOTAL COST IMPACT OF AMMONIA USAGE ON ALL COAL-FIRED UTILITY BOILERS INSTALLED BY 1985 -- HIGH COAL GROWTH CASE

Boiler Type	Coal Consumption EJ	Ammonia Consumption Rate ng/J	Total Ammonia Consumption 10^6 Mg/yr	Ammonia Cost 10^3 $/yr
Tangential	17.875	73.1	1.44	244,800
Single Wall	10.243	83.0	0.938	159,460
Opposed Wall and Turbo Furnace	2.924	86.4	0.278	47,260
Cyclone[a]	2.222	480.3	1.177	200,080
Vertical and Stoker	0.472		negligible	negligible
All Boilers	33.74	103.2[b]	3.833	652,975

[a]Assume no combustion modifications, maximum NO_x reduction of 57 percent with DeNO_x.
[b]Weighted average.

be required, which represents about a 20 percent increase in ammonia supply. For the low coal growth case, Table 4-15 shows that about $370 million would be expended to meet the low emissions targets. Also about 2×10^6 Mg of ammonia would be required, representing over a 10 percent increase in total ammonia supply.

4.2.4 Relative Impacts of Coal vs. Natural Gas Feedstocks on Ammonia Cost and Fuel Supply

Switching the feedstock from natural gas to coal will clearly impact the cost of ammonia. The synthesis of ammonia from coal will raise the cost per ton. For example, the cost of ammonia is $165/ton when produced from a typical bituminous coal, but only $150/ton when produced from natural gas feedstock (Reference 4-15). Although this incremental cost may be significant on a national scale, there are positive aspects derived from switching from a natural gas to a coal feedstock. In fact, a switch to coal could give U.S. producers a competitive edge because they will be able to get a premium on ammonia prices over prices charged by firms with interruptable gas supplies. For example, if natural gas supplies are interrupted, each day's lost production is likely to cost the operator (of a 1,000 metric ton/day ammonia plant) about $100,000, including loss of profit and built-up capital charges.

It has been suggested that coal-fired power plants could be combined with the production of ammonia. Such schemes could be based on well known synthesis gas generation processes. One modern variation of this process has been developed by Texaco Development Corporation and another by Union Carbide Corporation.

In addition to the cost impact, the fuel feedstocks needed to produce the additional ammonia will impact the national consumption of

TABLE 4-15. TOTAL COST IMPACT OF AMMONIA USAGE ON ALL COAL-FIRED UTILITY BOILERS INSTALLED BY 1985 -- LOW COAL GROWTH CASE

Boiler Type	Coal Consumption EJ	Ammonia Consumption Rate ng/J	Total Ammonia Consumption 10^6 Mg/yr	Ammonia Cost 10^3 $/yr
Tangential	10.214	73.1	0.824	140,515
Single Wall	5.853	83.0	0.536	91,071
Opposed Wall and Turbo Furnace	1.671	86.4	0.159	27,110
Cyclone[a]	1.270	480.3	0.673	114,469
Vertical and Stoker	0.270		negligible	negligible
All Boilers	19.278	103.2[b]	2.192	373,165

[a]Assume no combustion modifications, maximum NO_x reduction of 57 percent with $DeNO_x$.
[b]Weighted average.

coal and natural gas. Tables 4-16 and 4-17 show the impact of increased NH_3 consumption on coal and natural gas consumpted directly or indirectly by utilities in the year 1985. Assuming high coal growth, natural gas consumption or coal consumption would increase by either 0.9 percent or 0.5 percent to meet the requirement for the ammonia feedstock. For low coal growth, natural gas or coal consumption would have to increase by about 0.5 percent in either case to meet the need for the additional ammonia feedstock. Although small nationally, this impact could be significant regionally.

In summary, switching from a natural gas to a coal feedstock should not significantly impact either the cost or national energy consumption. Moreover, if long-term contractual agreements for coal resources can be obtained, the ammonia producers will have a major incentive to switch to coal resources, particularly if they face increasing natural gas cutoffs and decreasing supplies.

TABLE 4-16. IMPACT OF INCREASED NH_3 CONSUMPTION ON NATURAL GAS AND COAL FEEDSTOCK -- REFERENCE CASE HIGH COAL GROWTH

Boiler Type	Coal Consumption EJ	NH_3 Needed 10^6 Mg/yr	Natural Gas Needed for Synthesis EJ[b]	Coal Needed For Synthesis EJ[c]
Tangential	17.875	1.44	0.053	0.063
Single Wall	10.243	0.938	0.035	0.041
Opposed Wall and Turbo Furnace	2.924	0.278	0.010	0.012
Cyclone[a]	2.222	1.177	0.043	0.052
Vertical and Stoker	0.472	Negligible		
All Boilers	33.736	3.833	0.141 (0.86)[d]	0.168 (0.45)[d]

[a]Assume no combustion modifications, maximum NO_x reduction of 57 percent with $DeNO_x$
[b]1.1 x 10^6 SCM natural gas needed to make 10^6 grams of ammonia (37.26 MJ/SCM)
[c]1.18 Mg of coal needed to make 0.68 Mg of NH_3 (27,900 J/g)
[d]Percent of total fuel used in 1985

TABLE 4-17. IMPACT OF INCREASED NH_3 CONSUMPTION ON NATURAL GAS AND COAL FEEDSTOCK -- REFERENCE CASE LOW COAL GROWTH

Boiler Type	Coal Consumption EJ	NH_3 Needed 10^6 Mg/yr	Natural Gas Needed EJ[b]	Coal Needed EJ[c]
Tangential	10.214	0.824	0.030 (0.029)	0.036
Single Wall	5.853	0.536	0.020 (0.019)	0.023
Opposed Wall and Turbo Furnace	1.671	0.159	0.006 (0.006)	0.007
Cyclone[a]	1.270	0.673	0.025 (0.024)	0.030
Vertical and Stoker	0.270	Negligible		
All Boilers	19.278	2.192	0.081 (0.50)[d]	0.096 (0.45)[d]

[a]Assume no combustion modifications, maximum NO_x reduction of 57 percent with $DeNO_x$.
[b]1.1 x 10^6 SCM natural gas needed to make 10^6 grams of ammonia (37.26 MJ/SCM)
[c]1.18 Mg of coal needed to make 0.68 Mg of NH_3 (27,900 J/g)
[d]Percent of total fuel used in 1985

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SECTION 5

CONCLUSIONS AND RECOMMENDATIONS

1. Current NO_x regulatory strategy may require Thermal $DeNO_x$ for gas- and oil-fired utility boilers in the South Coast Air Basin of Southern California. Projected regulation strategy for the 1980's shows a probable need for Thermal $DeNO_x$ for coal-fired utility boilers.

2. The Thermal $DeNO_x$ Process is commercially available for gas- and oil-fired boilers. NO_x reductions in the range of 40-70 percent can often be achieved.

3. The Thermal $DeNO_x$ Process is not demonstrated for full-scale coal-fired boilers. Process conditions which could affect $DeNO_x$ performance and equipment operation need to be investigated. These include:

- Coal type on reaction temperature
- Coal fired utility boilers operating characteristics on flue gas temperature fluctuations and $DeNO_x$ performance
- NH_3 emissions on corrosion and fouling
- NH_3 emissions on SO_3 depletion and ESP efficiency
- Flue gas particulate loading on system performance and reliability

4. These effects cannot be easily quantified with the present data base. Currently ER&E is investigating the effect of coal type on reaction

temperature. However, it is recommended that further studies be performed to:

- Quantify ammonium sulfate and bisulfate formation and deposition with various coal types
- Assess the effect of NH_3 on SO_3 depletion and ESP performance with various coal and ESP types
- Monitor the ongoing efforts in Japan in the above areas.

Results from these three efforts will be beneficial to guide full-scale tests and aid in interpreting the results.

5. Furthermore, it is recommended that the Thermal $DeNO_x$ Process be installed on a full-scale coal-fired utility boiler equipped with combustion modifications to assess:

- The effectiveness of Thermal $DeNO_x$ used singly and in conjunction with combustion modifications
- The performance of the process at various loads and during a full operating cycle of the boiler, including slagging and fouling of furnace tubes which cause temperature fluctuations
- Sulfate formation, corrosion and plugging of boiler parts due to deposits of ammonia sulfates, especially air heaters and associated ducting
- Effect on ESP performance and resultant emissions of fine particles to the atmosphere
- Reliability of the injection system over extended operation
- Incremental maintenance due to the operation of the process
- Emissions of byproduct species in full-scale operation.

6. Based on potential limitations of the Thermal $DeNO_x$ Process identified in this report, the effectiveness forecast by Exxon for coal firing may prove to be optimistic. Significant reductions in $DeNO_x$ performance could occur if, for example, NH_3 emissions cannot be maintained at a minimum level.

7. Costs reported by Exxon should in general be increased by 9 percent on the average to include additional expenditures not considered. Licensing costs should also be added once they have been specified by Exxon.

8. If all existing and new coal-fired utility boilers were to meet low NSPS targets (172-129 ng/J) by 1985 with combined combustion modifications and Thermal $DeNO_x$, the increase in NH_3 consumption would range from 2.2 to 3.8 million Mg/year. The cost of this additional NH_3 to the utilities would range from 370 to 650 million dollars per year. The impact of this increase in ammonia production on feedstock fuels would be less than one percent of the total national gas and coal consumption in 1985.

APPENDIX A

GLOSSARY OF TERMS

TABLE A-1. GLOSSARY OF TERMS USED IN COST ANALYSIS CALCULATION PROCEDURE

AKW	=	Additional Fan Requirements, kW
AROY	=	Annual Royalties, $/yr
B1	=	Debt/Equity Ratio, fraction
CANAL	=	Cost of Analysis, $
CFE1	=	Construction Field Expense Factor, fraction
CF1	=	Construction Facilities Factor, fraction
CGA	=	Construction General & Administrative Expense, fraction
CON1	=	Contractor's Fee, fraction
CRATE	=	Composite Construction Crew Rate, $/h
CSUPV	=	Construction Supervision Factor, fraction
CTN1	=	Construction Contingency Factor, fraction
DESRAT	=	Designer's Rate, $/h
DHRS	=	Design Hours, h
DRATE	=	Derate of Boiler, kW
DS1	=	Design and Supervision Factor , fraction
EGA	=	Engineering and Design G&A, fraction
EHRS	=	Engineering Hours, h
EOHD	=	Engineering and Design Overhead, fraction
EOOS	=	Equipment Out of Service, $
ER	=	Electric Power Rate, $/kW
ERAT	=	Engineering Rate, $/hr
ESUPV	=	Engineering Supervision Factor, fraction
FCOST	=	Fuel Cost, $/$10^6$ Btu (1 Btu = 1.055 kJ)
FEER	=	Engineering Fee, fraction
FPEN	=	Fuel Penalty, fraction

TABLE A-1. Continued

FI	=	Federal Tax Rate, fraction
HRATE	=	Heat Rate of Boiler, Btu/kWh (1 Btu = 1.055 kJ)
HRINST	=	Installation Time, h
HYR	=	Annual Operating Time, h
IC	=	Initial Charges, $
IIO	=	Initial Investment of Boiler, $
ILAST	=	Computer Code Counter
INl	=	Insurance Factor, fraction
IOl	=	Interest on Borrowed Money, Original Investment, fraction
Il	=	Interest on Borrowed Money, Present Investment, fraction
K	=	Age of Existing Boiler, yr
KW	=	Power Rating of Boiler, kW
Ml	=	Maintenance Factor, fraction
N	=	Remaining Lifetime of Boiler, yr
NANAL	=	Number of Analyses Required
NLOST	=	Total Lifetime of Boiler, yr
NOBASE	=	Baseline NO_x Emissions, ppm
NOCONT	=	Controlled NO_x Emissions, ppm
NOP	=	Number of Operators
OHAl	=	Administrative Overhead Operating Labor Factor, fraction
OHPl	=	Power Plant Overhead, fraction
REl	=	Replacement Equipment Factor, fraction
RM	=	Raw Materials, $/yr
ROl	=	Return to Equity, Original Investment, fraction

TABLE A-1. Concluded

R1	=	Return to Equity, Present Investment, fraction
SC1	=	Startup Cost Factor, fraction
SF1	=	Service Facilities Factor, fraction
S1	=	State Tax Rate, fraction
PPR	=	Purchased Power Rate, $/kWh
TM	=	Total Materials (Hardware) Required, $
UF1	=	Utilities Facilities Factor, fraction
WAGE	=	Operating Labor Rate, $/h

APPENDIX B

COST INPUTS

TABLE B-1. COST INPUTS FOR RETROFIT OF NH_3 INJECTION ON 130 MW FRONT WALL COAL-FIRED BOILER

```
$INPUT
AKW      =    .00000000E+00
AROY     =    .00000000E+00
B1       =    .50000000E+00
CANAL    =    .00000000E+00
CFE1     =    .13000000E+00
CF1      =    .50000000E-01
CGA      =    .25000000E+00
CON1     =    .70000000E-01
CRATE    =    .15300000E+02
CSUPV    =    .10000000E+00
CTN1     =    .15000000E+00
DESRAT   =    .90000000E+01
DHRS     =    .00000000E+00
DRATE    =    .00000000E+00
DS1      =    .45000000E-01
EGA      =    .25000000E+00
EHRS     =    .00000000E+00
EOHC     =    .11000000E+01
EOOS     =    .00000000E+00
ER       =    .25000000E-01
ERAT     =    .12000000E+02
ESUPV    =    .10000000E+00
FCOST    =    .13000000E+01
FEER     =    .80000000E-01
FPEN     =    .00000000E+00
F1       =    .48000000E+00
HRATE    =    .92000000E+04
HRINST   =    .00000000E+00
HYR      =    .70000000E+04
IC       =    .00000000E+00
IIO      =    .00000000E+00
ILAST    =              +0
IN1      =    .50000000E-02
IO1      =    .80000000E-04
I1       =    .80000000E-01
K        =              +5
KW       =    .13000000E+06
M1       =    .50000000E-01
N        =             +25
NANAL    =    .00000000E+00
NLOST    =    .30000000E+02
NOBASE   =    .30000000E+03
NOCONT   =    .22500000E+03
NOP      =    .11900000E+00
OHA1     =    .10000000E+00
OHP1     =    .20000000E+00
RE1      =    .40000000E-02
RM       =    .15724000E+06
RO1      =    .12000000E+00
R1       =    .12000000E+00
SC1      =    .10000000E+00
SF1      =    .50000000E-01
S1       =    .60000000E-01
PPR      =    .26000000E-01
TM       =    .77830000E+06
UF1      =    .30000000E-01
WAGE     =    .10000000E+02
```

TABLE B-2. COST INPUTS FOR RETROFIT OF NH_3 INJECTION ON 333 HORIZONTALLY OPPOSED COAL-FIRED BOILER

$INPUT

AKW	=	.00000000E+00	IC	=	.00000000E+00
AROY	=	.00000000E+00	IIO	=	.00000000E+00
B1	=	.50000000E+00	ILAST	=	+0
CANAL	=	.00000000E+00	IN1	=	.50000000E-02
CFE1	=	.13000000E+00	IO1	=	.80000000E-04
CF1	=	.50000000E-01	I1	=	.80000000E-01
CGA	=	.25000000E+00	K	=	+5
CON1	=	.70000000E-01	KW	=	.33300000E+06
CRATE	=	.15300000E+02	M1	=	.50000000E-01
CSUPV	=	.10000000E+00	N	=	+25
CTN1	=	.15000000E+00	NANAL	=	.00000000E+00
DESRAT	=	.90000000E+01	NLOST	=	.30000000E+02
DHRS	=	.00000000E+00	NOBASE	=	.42000000E+03
DRATE	=	.00000000E+00	NOCONT	=	.30000000E+03
DS1	=	.45000000E-01	NOP	=	.11900000E+00
EGA	=	.25000000E+00	OHA1	=	.10000000E+00
EHRS	=	.00000000E+00	OHP1	=	.20000000E+00
EOHD	=	.11000000E+01	RE1	=	.40000000E-02
EOOS	=	.00000000E+00	RM	=	.43785000E+06
ER	=	.25000000E-01	RO1	=	.12000000E+00
ERAT	=	.12000000F+02	R1	=	.12000000E+00
ESUPV	=	.10000000E+00	SC1	=	.10000000F+00
FCOST	=	.13000000E+01	SF1	=	.50000000F-01
FEER	=	.80000000E-01	S1	=	.60000000E-01
FPEN	=	.00000000E+00	PPR	=	.26000000F-01
F1	=	.48000000E+00	TM	=	.11280000E+07
HRATE	=	.92000000E+04	UF1	=	.30000000E-01
HRINST	=	.00000000E+00	WAGE	=	.10000000E+02
HYR	=	.70000000E+04			

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TABLE B-3. COST INPUTS FOR RETROFIT OF NH_3 INJECTION ON 350 MW TANGENTIAL COAL-FIRED BOILER

$INPUT

AKW	=	.00000000E+00	IC	=	.00000000E+00
AROY	=	.00000000E+00	IIO	=	.00000000E+00
B1	=	.50000000E+00	ILAST	=	+0
CANAL	=	.00000000E+00	IN1	=	.50000000E-02
CFE1	=	.13000000E+00	IO1	=	.80000000E-04
CF1	=	.50000000E-01	I1	=	.80000000E-01
CGA	=	.25000000E+00	K	=	+5
CON1	=	.70000000E-01	KW	=	.35000000E+06
CRATE	=	.15300000E+02	M1	=	.50000000E-01
CSUPV	=	.10000000E+00	N	=	+25
CTN1	=	.15000000E+00	NANAL	=	.00000000E+00
DESRAT	=	.90000000E+01	NLOST	=	.30000000E+02
DHRS	=	.00000000E+00	NOBASE	=	.45000000E+03
DRATE	=	.00000000E+00	NOCONT	=	.30000000E+03
DS1	=	.45000000E-01	NOP	=	.11900000E+00
EGA	=	.25000000E+00	OHA1	=	.10000000E+00
EHRS	=	.00000000E+00	OHP1	=	.20000000E+00
EOHC	=	.11000000E+01	RE1	=	.40000000E-02
EOOS	=	.00000000E+00	RM	=	.50793000E+06
ER	=	.25000000E-01	RO1	=	.12000000E+00
ERAT	=	.12000000E+02	R1	=	.12000000E+00
ESUPV	=	.10000000E+00	SC1	=	.10000000E+00
FCOST	=	.13000000E+01	SF1	=	.50000000E-01
FEER	=	.80000000E-01	S1	=	.60000000E-01
FPEN	=	.00000000E+00	PPR	=	.26000000E-01
F1	=	.48000000E+00	TM	=	.11714000E+07
HRATE	=	.92000000E+04	UF1	=	.30000000E-01
HRINST	=	.00000000E+00	WAGE	=	.10000000E+02
HYR	=	.70000000E+04			

TABLE B-4. COST INPUTS FOR RETROFIT OF NH_3 INJECTION ON 800 MW TANGENTIAL COAL-FIRED BOILER

```
$INPUT
AKW      =     .00000000E+00
AROY     =     .00000000E+00
B1       =     .50000000E+00
CANAL    =     .00000000E+00
CFE1     =     .13000000E+00
CF1      =     .50000000E-01
CGA      =     .25000000E+00
CON1     =     .70000000E-01
CRATE    =     .15300000E+02
CSUPV    =     .10000000E+00
CTN1     =     .15000000E+00
DESRAT   =     .90000000E+01
DHRS     =     .00000000E+00
DRATE    =     .00000000E+00
DS1      =     .45000000E-01
EGA      =     .25000000E+00
EHRS     =     .00000000E+00
EOHD     =     .11000000E+01
EOOS     =     .00000000E+00
ER       =     .25000000E-01
ERAT     =     .12000000E+02
ESUPV    =     .10000000E+00
FCOST    =     .13000000E+01
FEER     =     .80000000E-01
FPEN     =     .00000000E+00
F1       =     .48000000E+00
HRATE    =     .92000000E+04
HRINST   =     .00000000E+00
HYR      =     .70000000E+04
IC       =     .00000000E+00
IIO      =     .00000000E+00
ILAST    =               +1
IN1      =     .50000000E-02
IO1      =     .80000000E-04
I1       =     .80000000E-01
K        =               +5
KW       =     .80000000E+06
M1       =     .50000000E-01
N        =              +25
NANAL    =     .00000000E+00
NLOST    =     .30000000E+02
NOBASE   =     .37500000E+03
NOCONT   =     .22500000E+03
NOP      =     .11900000E+00
OHA1     =     .10000000E+00
OHP1     =     .20000000E+00
RE1      =     .40000000E-02
RM       =     .13748290E+07
RO1      =     .12000000E+00
R1       =     .12000000E+00
SC1      =     .10000000E+00
SF1      =     .50000000E-01
S1       =     .60000000E-01
PPR      =     .26000000E-01
TM       =     .17154000E+07
UF1      =     .30000000E-01
WAGE     =     .10000000E+02
```

TABLE B-5. COST INPUTS FOR RETROFIT OF NH_3 INJECTION ON 350 MW FRONT WALL COAL-FIRED BOILER

$INPUT

AKW	=	.00000000E+00	IC	=	.00000000E+00
AKOY	=	.00000000E+00	IIO	=	.00000000E+00
B1	=	.50000000E+00	ILAST	=	+0
CANAL	=	.00000000E+00	IN1	=	.50000000E-02
CFE1	=	.13000000E+00	IO1	=	.80000000E-04
CF1	=	.50000000E-01	I1	=	.80000000E-01
CGA	=	.25000000E+00	K	=	+5
CON1	=	.70000000E-01	KW	=	.33000000E+06
CRATE	=	.15300000E+02	M1	=	.50000000E-01
CSUPV	=	.10000000E+00	N	=	+25
CTN1	=	.15000000E+00	NANAL	=	.00000000E+00
DESRAT	=	.90000000E+01	NLOST	=	.30000000E+02
DHRS	=	.00000000E+00	NOBASE	=	.51000000E+03
DRATE	=	.00000000E+00	NOCONT	=	.30000000E+03
DS1	=	.45000000E-01	NOP	=	.11900000E+00
EGA	=	.25000000E+00	OHA1	=	.10000000E+00
EHRS	=	.00000000E+00	OHP1	=	.20000000E+00
EOHD	=	.11000000E+01	RE1	=	.40000000E-02
EOOS	=	.00000000E+00	RM	=	.71540900E+06
ER	=	.25000000E-01	RO1	=	.12000000E+00
ERAT	=	.12000000E+02	R1	=	.12000000E+00
ESUPV	=	.10000000E+00	SC1	=	.10000000E+00
FCOST	=	.13000000E+01	SF1	=	.50000000E-01
FEER	=	.80000000E-01	S1	=	.60000000E-01
FPEN	=	.00000000E+00	PPR	=	.26000000E-01
F1	=	.48000000E+00	TM	=	.11902000E+07
HRATE	=	.92000000E+04	UF1	=	.30000000E-01
HRINST	=	.00000000E+00	WAGE	=	.10000000E+02
HYR	=	.70000000E+04			

TABLE B-6. COST INPUTS FOR RETROFIT OF NH_3 INJECTION ON 670 MW HORIZONTALLY OPPOSED COAL-FIRED BOILER

```
$INPUT
AKW      =      .00000000. +00      IC       =      .00000000E+00
AROY     =      .00000000E+00       IIO      =      .00000000E+00
B1       =      .50000000E+00       ILAST    =                +0
CANAL    =      .00000000E+00       IN1      =      .50000000E-02
CFE1     =      .13000000E+00       IO1      =      .P0000000E-04
CF1      =      .50000000E-01       I1       =      .E0000000E-01
CGA      =      .25000000E+00       K        =                +5
CON1     =      .70000000E-01       KW       =      .67000000E+06
CRATE    =      .15300000E+02       M1       =      .50000000E-01
CSUPV    =      .10000000E+00       N        =               +25
CTN1     =      .15000000E+00       NANAL    =      .00000000E+00
DESRAT   =      .90000000E+01       NLOST    =      .30000000E+02
DHRS     =      .00000000E+00       NOBASE   =      .42000000E+03
DRATE    =      .00000000E+00       NOCONT   =      .22500000E+03
DS1      =      .45000000E-01       NOP      =      .11900000E+00
EGA      =      .25000000E+00       OHA1     =      .10000000E+00
EHRS     =      .00000000E+00       OHP1     =      .20000000E+00
EOHD     =      .11000000E+01       RE1      =      .40000000E-02
EOOS     =      .00000000E+00       RM       =      .16487830E+07
ER       =      .25000000E-01       RO1      =      .12000000E+00
ERAT     =      .12000000E+02       R1       =      .12000000E+00
ESUPV    =      .10000000E+00       SC1      =      .10000000E+00
FCOST    =      .13000000E+01       SF1      =      .50000000E-01
FEER     =      .P0000000E-01       S1       =      .60000000E-01
FPEN     =      .00000000E+00       PPR      =      .26000000E-01
F1       =      .48000000E+00       TM       =      .16909000E+07
HRATE    =      .92000000E+04       UF1      =      .30000000E-01
HRINST   =      .00000000E+00       WAGE     =      .10000000E+02
HYR      =      .70000000E+04
```

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TABLE B-7. COST INPUTS FOR RETROFIT OF NH_3 INJECTION ON 350 MW TURBO COAL-FIRED BOILER

AKW	=	.00000000E+00	IC	=	.00000000E+00
AROY	=	.00000000E+00	IIO	=	.00000000E+00
B1	=	.50000000E+00	ILAST	=	+1
CANAL	=	.00000000E+00	IN1	=	.50000000E-02
CFE1	=	.13000000E+00	IO1	=	.60000000E-04
CF1	=	.50000000E-01	I1	=	.80000000E-01
CGA	=	.25000000E+00	K	=	+5
CON1	=	.70000000E-01	KW	=	.35000000E+06
CRATE	=	.15300000E+02	M1	=	.50000000E-01
CSUPV	=	.10000000E+00	N	=	+25
CTN1	=	.15000000E+00	NANAL	=	.00000000E+00
DESRAT	=	.90000000E+01	NLOST	=	.30000000E+02
DHRS	=	.00000000E+00	NOBASE	=	.42000000E+03
DRATE	=	.00000000E+00	NOCONT	=	.30000000E+03
DS1	=	.45000000E-01	NOP	=	.11900000E+00
EGA	=	.25000000E+00	OHA1	=	.10000000E+00
EHRS	=	.00000000E+00	OHP1	=	.20000000E+00
EOHD	=	.11000000E+01	RE1	=	.40000000E-02
EOOS	=	.00000000E+00	RM	=	.58574800E+06
ER	=	.25000000E-01	RO1	=	.12000000E+00
ERAT	=	.12000000E+02	R1	=	.12000000E+00
ESUPV	=	.10000000E+00	SC1	=	.10000000E+00
FCOST	=	.13000000E+01	SF1	=	.50000000E-01
FEER	=	.80000000E-01	S1	=	.60000000E-01
FPEN	=	.00000000E+00	PPR	=	.26000000E-01
F1	=	.48000000E+00	TM	=	.12063000E+07
HRATE	=	.92000000E+04	UF1	=	.30000000E-01
HRINST	=	.00000000E+00	WAGE	=	.10000000E+02
HYR	=	.70000000E+04			

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